Camal O. Robinson
Associate General Counsel

Duke Energy
550 South Tryon St
DEC45A
Charlotte, NC 28202

o: 980.373.2631
f: 704.382.4439
camal.robinson@duke-energy.com

November 4, 2020

Ms. Kimberly A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas LLC's Findings and Conclusions for Proposed Order Regarding Issues Unresolved by the Public Staff Partial Stipulations
Docket No. E-7, Sub 1213
Docket No. E-7, Sub 1214
Docket No. E-7, Sub 1187

Dear Ms. Campbell:

Enclosed for filing in the above-referenced dockets are the public and confidential versions of Duke Energy Carolinas, LLC's (DEC) Findings and Conclusions for Proposed Order Regarding Issues Unresolved by the Public Staff Partial Stipulations. These Findings and Conclusions are filed solely on behalf of DEC with the support of the following intervenors for certain portions as noted below:

a. Findings of Fact and Evidence and Conclusions for Findings of Fact Nos. 58-60, filed with the support of Harris Teeter, LLC and the Commercial Group;

b. Findings of Fact and Evidence and Conclusions for Findings of Fact Nos. 61-62, filed with the support of the Carolina Industrial Group for Fair Utility Rates III;

c. Findings of Fact and Evidence and Conclusions for Finding of Fact No.63, filed with the support of the North Carolina Sustainable Energy Association, North

Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy; and

d. Findings of Fact and Evidence and Conclusions for Finding of Fact No. 64 filed with the support of Vote Solar.

2. Confidential Pages of the Duke Energy Carolinas, LLC (DEC) Findings and Conclusions for Proposed Order Regarding Issues Unresolved by the Public Staff Partial Stipulations filed on behalf of DEC only. This document contains commercially sensitive information that should be protected from public disclosure. The information designated by DEC as confidential qualifies as "trade secrets" under N.C. Gen. Stat. § 66-152(3). If this information were to be publicly disclosed, it would allow competitors, vendors, and other market participants to gain an undue advantage, which may ultimately result in harm and higher cost to customers. Pursuant to N.C.G.S. § 132-1.2, DEC requests that the information marked "Confidential" be protected from public disclosure. DEC is filing all pages designed as confidential under seal and will make the information available to other parties to this docket pursuant to an appropriate nondisclosure.

If you have any questions, please let me know.

Sincerely,

/s/ Camal O. Robinson
Camal O. Robinson

Enclosures

cc: Parties of Record

Need for Rate Increase

57. The Company's request for an increase is driven by its need to keep pace with evolving customer needs and expectations by continuing to make investments that benefit North Carolina and its customers while preserving the Company's financial position and keeping prices as low as reasonably possible.

Harris Teeter Stipulation and Commercial Group Stipulation

58. The Commission finds and concludes that the provisions of the Harris Teeter Stipulation are just and reasonable in light of all the evidence presented and that the Harris Teeter Stipulation should be approved in its entirety.

59. The Commission finds and concludes that the provisions of the Commercial Group Stipulation are just and reasonable in light of all the evidence presented and that the Commercial Group Stipulation should be approved in its entirety.

60. The Commission finds and concludes that the rate design for the OPT-VSS rate schedule should be modified as provided in § 3 of the Harris Teeter Stipulation and § 3 of the Commercial Group Stipulation.

CIGFUR Stipulation

61. The Commission finds and concludes that the provisions of the CIGFUR Stipulation are just and reasonable in light of all the evidence presented and that the CIGFUR Stipulation should be approved in its entirety.

62. The Commission finds and concludes that unprotected EDIT and deferred revenue should be refunded to customers on a uniform cents per kWh basis as provided in the CIGFUR Stipulation and as illustrated in Pirro Second Settlement Ex. 9.

NCSEA and NCJC et al. Stipulation

63. The Commission finds and concludes that the provisions of the NCSEA and NCJC et al. Stipulation are just and reasonable in light of all the evidence presented and that the NCSEA and NCJC et al. Stipulation should be approved in its entirety.

Vote Solar Stipulation

64. The Commission finds and concludes that the provisions of the Vote Solar Stipulation are just and reasonable in light of all the evidence presented and that the Vote Solar Stipulation should be approved in its entirety.

Grid Improvement Plan

65. Deferral Accounting for the eight GIP programs agreed to between DEC and the Public Staff in the Second Partial Stipulation is also supported by separate settlements between DEC and several other intervenors in this docket.

66. When the Commission addresses recovery of deferred costs relating to GIP programs in the Company's next general rate case, the Commission will evaluate the appropriate methodology for allocating GIP costs. The Commission finds and concludes that the Public Staff's recommendation that DEC be required to study the allocation of GIP transmission and distribution investments based on the benefits realized prior to its next general rate case should be rejected.

Hydro Station Sale

67. The Company included an adjustment to amortize the loss on the sale of five hydro stations sold August 16, 2019, which was previously approved for deferral in Docket Nos. E-7, Sub 1181; SP-12478 Sub 0; and SP-12479, Sub 0. The Commission finds and concludes that the Company's requested amortization period of seven years with a revenue requirement impact of $3,249,000 for the loss on the sale of the hydro stations is just and reasonable in light of the evidence presented.

Coal Fleet Investments

68. The costs related to the Company's investments in its coal fleet were reasonably and prudently incurred for DEC to meet its obligation to provide safe, adequate, and reliable electric service. There is no credible or substantial evidence disputing the prudency or reasonableness of these costs.

69. It is not necessary or appropriate to impose a limit on the Company's future investments in its coal-fired generating assets.

Nuclear Fleet Investments

70. The costs related to the Company's investments in its nuclear generation fleet were reasonably and prudently incurred.

Depreciation

71. The depreciation rates proposed by DEC in this case, which are based on the Depreciation Study, filed by the Company as Spanos Ex. 1, and the Decommissioning Cost Estimate Study, filed by the Company as Doss Ex. 4 in Docket No. E-7, Sub 1146, are just and reasonable, and should be approved in this case.

Ratemaking Treatment of Recoverable CCR Costs

72. Since its last rate case, DEC has incurred additional costs to comply with federal and state legal requirements relating to its management and storage of coal ash.[1] These requirements mandate the closure of all of the Company's coal ash basins at all of

[1] Coal ash is also referred to as coal combustion residuals (CCR). The terms "coal ash" and "CCR" are used interchangeably throughout this order.

its coal-fired plants in North Carolina and South Carolina. Since its last rate case, DEC has incurred significant costs to continue the closure and compliance efforts that were begun prior to the prior rate case in order to comply with the Company's legal requirements.

73. On a North Carolina retail jurisdiction basis, the coal ash costs DEC has incurred for which it seeks recovery amount to approximately $378 million, approximately $342 million of which are the actual coal ash basin closure and compliance costs incurred by the Company during the period from January 1, 2018, through January 31, 2020, and the remainder of which are the financing costs incurred by the Company upon these deferred costs through July 2020. DEC is entitled to recover its actual coal ash basin closure and compliance costs. These costs are known and measurable, reasonable and prudent, and, used and useful in the provision of electric service to the Company's customers. DEC is also entitled to a return on those costs, at its weighted average cost of capital authorized in this case, during the period those costs have been deferred, through July 2020. Further, DEC proposes that its actual and financing costs referenced herein, totaling approximately $378 million, be amortized over a five-year period, and that it earn a return on the unamortized balance. The five-year amortization period proposed by the Company is appropriate and reasonable and should be approved. The Company is entitled to earn a return on the unamortized balance at its weighted average cost of capital authorized in this case.,

74. DEC further requests authorization to continue to defer this type of environmental cost, specifically, CCR compliance spend related to coal ash basin closure costs beginning February 1, 2020, the depreciation and return on CCR compliances investments related to continued plant operations placed in service after January 31, 2020, and a return on both the deferred balances at the overall rate of return approved in this case, for cost recovery consideration in a future rate case. The Company's request to continue to defer these ongoing costs is reasonable and appropriate and should be approved.

Revenue Requirement

75. The appropriate base revenue requirement is $413,433,000, to be further adjusted by the Public Staff's recommended adjustments to the May 2020 Updates described in Public Staff witness Boswell's Second Supplemental and Stipulation Testimony filed on September 8, 2020, and which the Company accepts.[2] In addition, the Company requests that customer rates be reduced by $310,779,000 through its proposed EDIT Rider,[3] resulting in a net proposed increase in revenue of $103,654,000, as

[2] The Company's revenue requirement will be revised to incorporate the impact of the Public Staff's May 2020 Updates adjustments, as discussed further herein, when the Company makes its compliance filing in accordance with this Order.

[3] The EDIT Rider is separately addressed in Findings of Fact Nos. 20-23.

adjusted.[4] This revenue increase is based on the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base (under present rates), which are to be used as the basis for setting rates in this proceeding: $5,209,138,000 of operating revenues, $4,000,325,000 of operating revenue deductions, and $17,166,748,000 of original cost rate base.[5]

76. The base non-fuel and base fuel revenues approved herein are just and reasonable to the customers of DEC, to DEC, and to all parties in this proceeding, and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 57

The evidence supporting this finding and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witnesses De May, D'Ascendis, Fetter, Hatcher, Newlin and Young, and the entire record in this proceeding.

Need for Rate Increase

Company witness De May testified that the Company's operations have continued to evolve since the Company's last rate case filing in 2017, challenging the Company's ability to continue to provide the type of electric service that customers expect. (Tr. vol. 11, 857.) The expenses driving the need for a base rate increase are investments the Company has made and must continue to make to keep pace with evolving customer needs and expectations. (Id.) Company witness Hatcher testified that DEC is a well-run company and that customers see and experience the benefits of the Company's efforts every day. (Tr. vol. 11, 910.) However, witness De May testified that the energy sector is in a period of transformation and profound change driven by technological advancements, environmental mandates, storm activity and response, energy security and resiliency efforts, as well as changing customer expectations. (Id.) Witness De May explained that the Company's Application reflects three general themes that demonstrate DEC's attention to the needs of its customers: (1) improving the customer experience and reliability, (2) moving past coal, and (3) low-income customer support. (Id. at 857-61.)

Witness De May testified that technology is transforming North Carolina and changing the way customers use electricity and interact with their electric supplier. (Id. at 858.) He explained that reliability remains essential as an increasingly connected population continues to expand, especially in the urban areas of North Carolina. (Id.) He explained that today, customers want a new and better experience, driven by information about how they consume energy and by tools to help them manage their consumption.

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[4] As adjusted per the Public Staff's May 2020 Updates audit recommendations, which the Company accepts.

[5] As adjusted per the Public Staff's May 2020 Updates audit recommendations, which the Company accepts.

(Id.) Witness De May explained that the Company's Grid Improvement Plan and its deployment of smart meters will continue to improve the customer experience and reliability. (Id.)

Witness Hatcher stated that the Company works each day to make its power system more efficient, more diverse and more reliable. (Id. at 911-12.) In fact, over the years, DEC has become a leader in efficiency. (Id.) Additionally, the percentage of time the Company's fossil-fueled power plants are available to generate power is at or above the NERC average for comparable units. (Id.) Another example witness Hatcher provided is that the Company is investing in ways to make its infrastructure smarter, cleaner, more efficient and less reliant on any single fuel source, which according to witness Hatcher leads to more reliable energy and a better experience for the Company's customers. (Id.)

Witness De May detailed how the Company is actively working towards achieving a lower carbon future by taking steps to close the final chapters on coal ash and reducing its reliance on coal-fired generation. (Id. at 859.) Witness De May provided an overview of investments the Company is making to dispose of coal combustion residuals, including the investments necessary to support ash basin closure activities, in compliance with federal and state regulatory requirements. (Id.) He testified that the Company's fossil/hydro fleet is investing in natural gas and solar, and as part of the Company's strategy to reduce its reliance on coal, DEC has taken a fresh look at the viability of several of its coal-fired plants and concluded that making shifts in the expected remaining depreciable lives of some of those assets is a reasonable action to take now. (Id.)

In terms of sustainability, witness Hatcher explained that he is proud of what the Company is doing in terms of sustainability goals and how those goals are in alignment with clean and affordable energy as well as protecting the planet and climate action. (Tr. vol. 12, 29-30.) As examples, witness Hatcher stated that since 2005, the Company has reduced its carbon emissions by 39% by the way the Company manages its generation fleet, and is on track to be at 50% carbon reduction by 2030; the Company has invested heavily in solar, with North Carolina having the second largest solar capacity in the country behind California, and plans to invest heavily in battery storage in the future. (Id.) In addition, witness De May added that the Company's high performing nuclear fleet has and will continue to provide North Carolina carbon free generation now and into the future. (Id. at 860.) For example, in 2018, DEC's nuclear fleet achieved a 95% capacity factor, marking the 19th consecutive year above 90%. (Id.) Witness Hatcher also noted that the Company's achievements have been accomplished while maintaining rates that are below the national average even with the full projected rate increase. (Id. at 915.)

Witness De May further outlined how the Company is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during periods of financial hardship. (Id.) He outlined assistance programs the Company offers to help customers reduce their energy costs such as Share the Warmth and the Company's portfolio of demand-side management and energy efficiency programs, including the Neighborhood Energy Saver Program. (Id.) As a further rate impact mitigation measure, witness De May testified that the Company has proposed a return on equity of 10.3% instead of the 10.5% that witness D'Ascendis' s analysis supports as the appropriate ROE for the Company. (Id.) Witness De May also explained that despite warranting an increase, the Company has not requested an increase in the Basic Facilities Charge (BFC) for customers to allow the Company and stakeholders an opportunity to collaborate on ways to help lower-income customers. (Id.) Witness De May further detailed the Company's commitment to making proactive decreases, such as removing a percentage of executive compensation costs to give customers the benefit of reductions that the Company agreed to in prior rate cases and the Company's proposal to eliminate direct credit card fees for all residential customers who pay their electric bill in this way. (Id. at 861.) Witness De May also outlined additional ideas for low-income energy assistance programs such as: (1) Low-Income Bill Credit on the BFC; (2) voluntary Bill Round-Up program; and (3) Expansion and Retooling of the Supplemental Security Income Price Discount. (Id. at 861-62.) Witness De May further explained that the Company's commitment to customer assistance expanded through the many settlements reached with intervening parties in this case, including significant contributions of shareholder funds to low-income energy assistance programs – a total of $8 million over the next two years. (Tr. vol. 11, 893.)

Regarding the Tax Act, witness De May explained that the proposed rates include a reduction from the corporate income tax rate from 35% to 21%. (Tr. vol. 12, 863.) He further noted that the Company included a proposal to return to customers, through a rider, excess federal and state income taxes and deferred revenue resulting from federal tax reform legislation, as well as reductions in the North Carolina corporate income tax rate. (Id.)

Witnesses De May and Young stressed the importance of maintaining a strong financial position for the Company to continue to invest in its infrastructure to make it stronger, smarter, cleaner and more efficient. Company witnesses Newlin and Young testified extensively regarding the capital-intensive nature of the utility industry and their reliance on third-party capital to finance critical infrastructure investments. (Tr. vol. 1, 54; Tr. vol. 3, 39.) Witness Young testified that "Duke Energy generates roughly 5 billion a year in operating cash flow after payment of dividends to its shareholders. This compares to roughly 10 billion a year in capital investments, meaning that we consistently operate on a significantly negative cash flow basis." (Tr. vol. 3, 38-39.) In other words, he explained, "we don't have a stash of money to sit there. We've got – when we've got to do things, we have to go out and borrow that money." (Tr. vol. 3, 47.) Witness De May noted that the single-most determinative factor of a healthy balance sheet and strong financial position is timely recovery of costs and the ability to generate cash flows sufficient to meet obligations as they become due, in all market conditions. (Id. at 864.)

Witness De May testified that historically, because of its financial position, the Company has had the financial strength and flexibility necessary to fund its long-term capital requirements, as well as meet short-term liquidity needs, at an economical cost to customers. (Id.) Witness De May further explained that ready access to capital is critical for the Company to continue serving customers. (Id.) He explained that access to capital is most assured for companies who have strong financial positions, strong investmentgrade credit ratings, and adequate cash flow generation to meet obligations as they become due. (Id.)

Witness Newlin explained that maintaining strong credit ratings is important because the Company must compete for third-party capital in the credit markets and that investors "vote with their wallets" and will invest elsewhere if the returns they see from the Company do not meet their requirements or that credit quality will be maintained over the life of their investment. (Tr. vol. 1, 57.) Company witness Fetter further highlighted the significance of strong credit ratings for capital-intensive industries:

> … Duke Carolinas' credit profile is especially important in view of its need to access substantial amounts of debt and equity, on a near daily basis, to fund its ongoing operations, including capital investments. This includes coal ash remediation activities, along with capital investment related to day-to-day maintenance and infrastructure enhancement related to its ongoing duty to serve customers in a safe and reliable manner. Significantly, a regulated utility is required to raise funding even if the markets are in turmoil and costs are escalating wildly. Strong credit ratings, like those currently held by the Company, limit the negative effects of having to finance at times of great volatility within the capital markets, as was seen back during the 2008-2009 recession when 'BBB'-rated utilities were subject to significantly higher interest rates than 'A'-rated utilities, along with more restricted access, if available at all, along with stricter financing terms.

Financial flexibility, witness De May explained, comes from the ability to access cost-effective capital in all market conditions, which serves the best interest of customers. (Id.) Witness Young testified that the utility sector was hurt by COVID more so than most other industry sectors and has traded below the S&P 500 since COVID by 15%. (Tr. vol. 3, 45.) Further, witness D'Ascendis testified that the markets are expected to remain volatile through at least the end of 2021. (Tr. vol. 2, 44). The Company presented evidence that strong credit ratings provide more flexibility for DEC to time when it goes to the market for financing and its financial strength has afforded it the ability to stay out of the market when financing terms are unfavorable. Witness Young testified that "we were able to ride through COVID entirely because our strong credit ratings allowed us to ride through with other sources of short-term capital. As the ratings drop, your access to commercial paper, the lifeblood of daily investments, shrink significantly." (Tr. vol. 3, 55.) "And that is part of the reason why our rates are low, is we've been able to access efficiently and effectively across our portfolio and to utilize our resources in this fashion to get the lowest cost debt," he explained. (Id.) Witness Newlin testified that:

> … during the COVID crisis. The Commercial paper markets, especially from A2/P2 issues like Duke Energy, widened greatly. And for some tenor of securities it wasn't available. Overnight was available, but a lot of times a 30- to 40- day type of borrowing in commercial paper was not available during March. And so that market can be somewhat fickle. Now, within the credit facility from the banks, which we use as a backup for commercial

> paper, it's more expensive, but it will be, you know, based on a draw based on a LIBOR or underlying floating rate of interest, and that amount also expanded greatly. So the cost of capital can be pretty expensive during times of dislocations.

(Tr. vol. 1, 105-06.) Furthermore, in the event the Company does have to access the market during periods of volatility, the Company emphasized the fact that strong credit ratings provide the Company with greater likelihood of access to the capital markets on reasonable terms.

Discussion and Conclusion

As witness De May testified, within this period of transformation and profound change facing the electric sector, the Company's most important objective is to continue providing safe, reliable, affordable, and increasingly clean electricity to its customers with high quality customer service, both today and in the future. (Id. at 865-66.) The Commission agrees with witness De May's conclusion that the Company's Application is made to support investments that benefit North Carolina and its customers while preserving the Company's financial position all while keeping prices as low as reasonably possible. (Id. at 866.) Accordingly, the Commission finds that the Company has sufficiently demonstrated its need for a rate increase.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 58-60

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witnesses Schneider, Pirro and Huber; Public Staff witness Floyd; Commercial Group witness Chriss; Harris Teeter witness Bieber; the Second Partial Stipulation, the Harris Teeter Stipulation, the Commercial Group Stipulation, and the entire record in this proceeding.

As discussed above, the Company entered into settlements with Harris Teeter and the Commercial Group. The Harris Teeter and Commercial Group Stipulations resolve a number of issues between DEC and these parties, including ROE and capital structure, as well as certain issues relating to, among other things, GIP and rate design. Based on all the evidence in the record, the Commission finds and concludes that the provisions of the Company's settlement agreements with Harris Teeter and the Commercial Group are just and reasonable and that each of these settlements should each be approved in its entirety. The Commission addresses the substantive provisions, and in particular the terms of the Harris Teeter and Commercial Group Stipulations relating to rate design of OPT-VSS challenged by the Public Staff, in more detail below.

ROE and Capital Structure

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 24-30, as part of the Harris Teeter and Commercial Group Stipulations, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the

Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. (Harris Teeter Stipulation, § 4; Commercial Group Stipulation, § 4.) Subsequently, DEC and the Public Staff entered into the Second Partial Stipulation which, among other things, stipulated to an ROE of 9.6%. The parties to the Harris Teeter and Commercial Group Stipulations amended their respective agreements to recognize that if the Commission issues an order approving an ROE of 9.6%, the parties to the Harris Teeter and Commercial Group Stipulations agree that the provisions of their respective agreements regarding ROE have been met. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 24-30, the Commission finds 9.6% to be a reasonable ROE for DEC and finds 52% equity and 48% debt to be a reasonable capital structure for DEC in this general rate case.

Grid Improvement Plan

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 31-33 and 65, as part of it settlement agreement with DEC, Harris Teeter supports the approval of DEC's requested GIP deferral with certain conditions detailed therein, including a reservation of Harris Teeter's right to take any position as to the reasonableness of specific GIP costs in a future rate case. (*See* Harris Teeter Stipulation, § 1.) The Commercial Group does not oppose nor specifically support the approval of the Company's requested GIP deferral. (Commercial Group Stipulation, § 1.) As discussed in the Evidence and Conclusions for Findings of Fact Nos. 31-33 and 65, the Commission finds the GIP related provisions of the settlements between the Company and the Public Staff and the other intervenors supporting or not opposing GIP implementation are reasonable and appropriate.

Green Button

Company witness Schneider described a new program through which DEC customers would be able to download usage data in a format consistent with the Green Button "Download My Data" standard. (Tr. vol. 13, 142.) Commercial Group witness Chriss recommended that in addition to supporting "Download My Data" functionality, the Commission require the Company to include Green Button "Connect My Data" functionality to allow a customer or a customer-authorized third party to download data automatically through an application programming interface. (Tr. vol. 16, 77-78.) Pursuant to § 5 of the Commercial Group Stipulation, the Commercial Group agrees that the Company has met with its representatives and adequately addressed its concerns regarding meter data access and Green Button functionality. No party disputed this provision of the Commercial Group Stipulation, and if the parties are satisfied that they have resolved the issues between them, then the Commission sees no reason not to approve this provision of the Commercial Group Stipulation. As such, the Commission determines that no further action is required with respect to witness Chriss's recommendation relating to Green Button "Connect My Data" functionality.

OPT-VSS

DEC's OPT-V rate schedule is a time of use rate class that provides separate rates for customers of varying size and delivery voltage. (Bieber Direct,[6] at 5.) The rate structure consists of three voltage levels: transmission, primary, and secondary. (Tr. vol. 12, 268.) Within the primary and secondary voltage levels there are three separate sizes of load (small, medium, and large) for a total of seven different rate offerings within OPT-V. (Id.) In his direct testimony, witness Pirro testified that the Company has generally proposed a uniform percentage increase for commercial and industrial rates. (Id. at 248.) He explained that the energy prices for OPT-V were adjusted to reflect the overall increase for each OPT-V size/voltage category. (Id.) The demand rates were then adjusted to achieve the required revenue requirement under each size/voltage category, with slightly more emphasis on winter demand rates due to the difference between summer and winter marginal cost narrowing over the past years. (Id. at 248-49.)

Harris Teeter witness Bieber testified that the Company's current OPT-V small secondary rate schedule (OPT-VSS) consists of a basic facilities charge, summer and winter on-peak demand charges, and economy demand charge, and on-peak and off-peak energy charges. (Bieber Direct, at 5.) He testified that the rate design for OPT-VSS understates demand-related charges while overstating the energy charges relative to the underlying cost components. (Id. at 4.) Under the Company's proposed rates, the OPT-VSS energy charges would increase by more than 9%, while according to the Company's unit cost study, the proposed energy-related costs for OPT-VSS increased by less than 2%. (Id. at 7.) Witness Bieber recommended modifications to the proposed OPT-VSS rate design that he believes will improve the alignment between the rate component and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts. (Id. at 4.)

In its settlements with Harris Teeter and the Commercial Group, DEC agreed that the OPT-VSS off-peak energy charge shall be set at 3.0222 cents per kWh and the on-peak energy charge shall be increased by a percentage amount that is equal to half of the overall percentage increase for the OPT-VSS rate schedule. (Harris Teeter Stipulation, § 3; Commercial Group Stipulation, § 3.) In addition, the settlements provide that the demand charges for the OPT-VSS rate schedule shall be adjusted by the amount necessary to recover the final OPT-VSS revenue target. (Id.)

In his second supplemental testimony, Public Staff witness Floyd testified that the Public Staff does not agree with all of the rate design terms of the Harris Teeter and Commercial Group settlements at this time. (*See* Tr. vol. 18, 338.) In his opinion, it would be premature to begin redesigning rates and the terms of service under specific rate schedules, without having a full understanding of the rationale for the change and the

[6] On October 29, 2020, an errata filing was made indicating that witness Bieber's testimony was inadvertently omitted from Volume 16 of the hearing transcripts. As of the filing of this proposed order, Volume 16 has not yet been corrected to add witness Bieber's testimony, so the Company has cited to the page numbers from his pre-filed direct testimony.

impact on other rate schedules and revenues. (Id.) According to witness Floyd, making discrete changes to individual rate schedules constrains the ability to conduct a comprehensive study of rates and rate design in the future. (Id.) He raised concerns that limiting the off-peak energy charge for OPT-VSS to a specific amount as provided for in DEC's settlements with Harris Teeter and the Commercial Group could impact other OPT and non-OPT customers and also argued that such changes would make a comprehensive rate study, "a little less comprehensive." (Id. at 339.)

During the evidentiary hearing, witness Pirro explained that OPT-VSS has its own revenue requirement, so there is no shifting of revenues or recoveries to any other customers within any of the other six options within OPT-V. (Tr. vol. 13, 22.) In other words, the modifications to OPT-VSS outlined in the Harris Teeter and Commercial Group Stipulations do not impact other customers within the OPT-V class or otherwise. (*See* id.) Witness Pirro also explained that the intent of the OPT-V pricing was to offer attractive off-peak energy pricing for high load factor customers to run their operations more efficiently and to allow them to plan their business operations to shift load to off-peak. (Id. at 23.) In the prior rate case, the Company used a 4-to-1 on-peak to off-peak ratio for the percentage increase to accomplish this objective. (*See* id.) In this case, the Company originally applied a more uniform increase to both on-peak and off-peak. (Id.) Witness Pirro concluded that the OPT-VSS pricing under the Harris Teeter and Commercial Group Stipulations is "more in line with the true intent of the OPT-V offering." (*See* id.)

Witness Pirro also provided testimony explaining how the parties arrived at the 3.0222 cents per kWh off-peak energy charge, indicating that the result is a 2% increase to the off-peak energy rate, with 50% of the overall percentage increase allocated to OPT-VSS being recovered through the on-peak energy charge, and the remaining revenue requirement being collected via the demand charge. (Id.) He concluded that this is an attractive price with an increase that is in line with the Company's compliance filing in its previous rate case and indicated that he is "very comfortable with where these rates have fallen out." (Id.)

Witness Pirro added:

> listening to Mr. Floyd's testimony, I know he had concerns about the comprehensive rate study and, you know, setting a price. By no means does this exclude any of the seven different options within OPT-V from being part of any comprehensive rate study. This is just for this moment in time while these rates are in effect.

(Id. at 24.) Company witness Huber also agreed that DEC views the rate design study as a "blank slate." (Id. at 71-72.)

During the evidentiary hearing, witness Floyd confirmed that the gist of his opposition to the Commercial Group Stipulation is that he would prefer not to make any changes to rate schedules now that might impact a future study of rate design, noting that he has "approached this whole subject with a rather cautionary stance." (Tr. vol. 19, 11-12.) In response to cross-examination from counsel for the Commercial Group, witness

Floyd indicated that he is not substantively opposed to the OPT changes in the Commercial Group Stipulation per se. (Id. at 14.) He testified:

> I think Mr. Pirro in his testimony conveyed that that rate was developed taking into account a better understanding of the on-peak/off-peak cost relationships, rather than simply applying an across-the-board percentage increase. That being said, I have not seen any analysis behind that, but I take him at his word. I've had a good working relationship with Mr. Pirro. If that's the case, then that is a positive step in rate design. However, that is an isolated adjustment or change in structure. And again, my cautionary stance is predicated on looking at all of the factors: OPT, residential, lighting, the whole works.

Similarly, in response to questioning from counsel for Harris Teeter about the identical OPT-VSS provision included in the Harris Teeter Stipulation, witness Floyd indicated that he does not think "the Public Staff has any literal fundamental concern with the $0.03 off-peak energy rate," and agreed that "literally" it is true that the rate design changes agreed to by Harris Teeter and DEC do not impact any customers taking service on any other rate schedule aside from OPT-VSS, but nevertheless testified that he does not have a full understanding of the impacts of these changes and suggested that the Commission take a "cautious approach." (Id. at 64-65.) He later indicated that the oral testimony provided by witness Pirro "shed some light on how that rate was established" and implied that it gave him a better understanding of the rationale for the changes to the OPT-VSS rates that the parties agreed to in the Harris Teeter and Commercial Group Stipulations. (*See* id. at 66.)

The Commission observes that the rate design provisions outlined in § 3 of the Harris Teeter and Commercial Group Stipulations apply only to the OPT-VSS rates proposed in *this* rate case. These provisions do not bind the Company to any particular rate design structure in a future rate case and do not limit the Company's ability to study alternative rate designs. The Commission gives weight to testimony from witnesses Huber and Pirro to the effect that the Company views the comprehensive rate design study as a "blank slate." In addition to evaluating new and innovative rate designs and exploring the topics discussed in the direct testimony of witness Floyd as well as witness Huber, it is clear from the evidence presented that DEC plans to use the study as an opportunity to review and reevaluate all of its existing tariffs, to include its offerings under OPT-V. Moreover, testimony from witnesses Pirro and Bieber indicates that the changes to the OPT-VSS rate design agreed to in the settlements with Harris Teeter and the Commercial Group in this rate case are reasonable, based on cost causation, and align with the intent of the OPT-V rate schedule. Further, witness Floyd acknowledged that he is not substantively opposed to these modifications. Accordingly, the Commission finds and concludes that the rate design for the OPT-VSS rate schedule should be modified as DEC has agreed in § 3 of the Harris Teeter Stipulation and § 3 of the Commercial Group Stipulation.

GIP Costs Allocated to OPT-V Customers

In its settlement agreements with Harris Teeter and the Commercial Group, DEC agreed that any GIP costs allocated to OPT-V customers shall be recovered by OPT-V demand charges. (Harris Teeter Stipulation, § 2; Commercial Group Stipulation, § 2.) This provision pertains to a certain methodology the Company agrees to propose in the future. The Commission will address recovery of deferred costs relating to GIP programs in the Company's next general rate case, and in that future rate case, the Commission will evaluate whether the Company's proposed allocation methodology is the appropriate way to allocate GIP costs both among customer classes, as well as within each individual rate schedule. Of course, the various parties are free to intervene and advocate the positions they believe are appropriate in the next rate case. Accordingly, the Commission finds and concludes that this provision is just and reasonable as part of its overall approval of the Harris Teeter and Commercial Group Stipulations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 61-62

The evidence supporting these findings of fact and conclusions are contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witnesses Hager and Pirro; the testimony and exhibits of CIGFUR witness Phillips; the Second Partial Stipulation, the CIGFUR Stipulation, and the entire record in this proceeding.

As discussed above, the Company entered into a settlement agreement with CIGFUR which resolves a number of issues between the parties, including ROE and capital structure, as well as certain issues relating to GIP, cost allocation, and rate design. Based on all the evidence in the record, the Commission finds and concludes that the provisions of the CIGFUR Stipulation are just and reasonable and that the CIGFUR Stipulation should be approved in its entirety. The Commission addresses the substantive provisions, and in particular the terms of the CIGFUR Stipulation relating to rate design and cost allocation challenged by the Public Staff, in more detail below.

ROE and Capital Structure

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 24-30, as part of the CIGFUR Stipulation, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. (CIGFUR Stipulation, § II.) Subsequently, DEC and the Public Staff entered into the Second Partial Stipulation which, among other things, stipulated to an ROE of 9.6%. CIGFUR and DEC amended the CIGFUR Stipulation to recognize that if the Commission issues an order approving an ROE of 9.6%, the parties agree that the provisions of their agreement regarding ROE have been met. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 24-30, the Commission finds 9.6% to be a reasonable ROE for DEC and finds 52% equity and 48% debt to be a reasonable capital structure for DEC in this general rate case.

Grid Improvement Plan

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 31-33 and 65, as part of its settlement agreement with DEC, CIGFUR supports the approval of DEC's requested GIP deferral with certain conditions detailed therein, including a reservation of its right to review and object to the reasonableness of specific GIP costs in a future rate case. (*See* CIGFUR Stipulation, § III.) As discussed in the Evidence and Conclusions for Findings of Fact Nos. 31-33 and 65, the Commission finds the GIP-related provisions of the settlements between the Company and the Public Staff and the other intervenors supporting or not opposing GIP implementation are reasonable and appropriate.

Rate Design for EDIT Rider

In § IV of the CIGFUR Stipulation, DEC and CIGFUR agree that the unprotected EDIT and deferred revenue giveback to be provided through the EDIT Rider should be refunded to customers on a uniform cents per kWh basis.

In his direct testimony, Company witness Pirro testified that over a lengthy period, residential customers have been subsidized by other customer classes. (Tr. vol. 12, 252; *see also* Pirro Ex. 5.) This historical subsidy has, in the past, been beyond the range of reasonableness, which he defines as class rates of return within 10% of the total Company rate of return. (Id.) The updated comparison through the test period year now shows significant convergence of the class rate of return over all classes towards the band of reasonableness in accordance with the Company's strategy of gradually reducing the subsidy/excess by 25%. (Id.) Witness Pirro concluded that continuation of this trend would be encouraging and desirable and noted that the Company remains committed to monitoring subsidy/excess levels and making improvements to ensure its rates are fair across the classes of customers served. (Id. at 252-53.)

In his supplemental direct testimony, Company witness Pirro described how the Company initially proposed to spread the EDIT Rider among customer classes. (Tr. vol. 12, 259-60.) He explained that the EDIT Rider for North Carolina was allocated to the customer classes based on how accumulated deferred income tax was allocated in the Company's 2018 per books cost of service study using the SCP methodology. (Id. at 259.) In order to develop the EDIT Rider rates, the rate design team grouped the allocated costs into four classes (Residential, General, Industrial, and Lighting). (Id.) The rate class revenue requirement was then divided by test year retail billed sales to establish the Year 1 credit rate. (Id.) He indicated that the derivation of the credit rate applicable to each rate class was provided in Pirro Ex. 9. (Id.) Furthermore, the proposed EDIT Rider rates, by class, were then multiplied by the kWh by rate schedule to develop the amounts shown in Pirro Direct Ex. 4, Column M. (Id. at 259-60.)

In his second settlement testimony, witness Pirro provided updates to Pirro Ex. 4 and Pirro Ex. 9 to reflect the Public Staff Partial Stipulations and the Company's settlement agreement with CIGFUR. (Id. at 276.) As a result of the Company's First Partial Stipulation with the Public Staff, the Company agreed to return protected federal EDIT to customers through base rates instead of the EDIT Rider. (Id. at 277-78.) In addition, in the Second Partial Stipulation, the Company and the Public Staff agreed that all unprotected federal EDIT should be returned to customers over a five-year amortization period and that North Carolina EDIT and deferred revenues related to the provisional overcollection of federal income taxes should be returned to customers over a two-year amortization period. (Id. at 278.) Under the CIGFUR Stipulation, the Company agreed to refund unprotected EDIT and deferred revenues to customers on a uniform cents per kWh basis. (Id.) Pirro Second Settlement Ex. 9 recalculates the proposed EDIT Rider rate credits to reflect these provisions of the First Partial Stipulation, Second Partial Stipulation, and CIGFUR Stipulation. (Id.)

In his second supplemental testimony, Public Staff witness Floyd explained that the Company and the Public Staff agreed to use a levelized rider to return EDIT, i.e., a rider that would be at the same level each year. (Tr. vol. 18, 334.) In the CIGFUR Stipulation, DEC agreed to return EDIT to customers on a uniform cents per kWh basis, i.e., through a rider wherein each customer would receive the same credit amount per kWh. (Id.) Witness Floyd argued that the method agreed upon in the CIGFUR Stipulation would benefit industrial customers, whereas the method he has used to distribute the EDIT credit by returning the monies to customer classes based on amounts each class paid, would be fairer. (Id.)

During the evidentiary hearing, in response to cross-examination from the Public Staff, witness Pirro confirmed that in his original calculation of the EDIT Rider, the Company developed class-specific EDIT credit rates that returned the excess deferred taxes to each class in proportion to how much each class had paid. (Tr. vol. 13, 27-28.) He agreed that the under the CIGFUR Stipulation, the OPT-V class would receive more of an EDIT credit than it had paid, but pointed out that in terms of base rates, “residential customers have been and continue to be subsidized by non-residential customers. And this was a way to sort of balance that. You know, rate design is sort of an art, and you try to be fair, just, and reasonable and find balances, so this was just a way of trying to balance that…and not have further subsidies just continue.” (Id. at 28-29.) He also indicated that the uniform cents per kWh methodology agreed to in the CIGFUR Stipulation is consistent with the method used to calculate the North Carolina EDIT Rider approved by the Commission in the Company’s last rate case. (*See* id. at 28, 74-75.)

CIGFUR witness Phillips testified that he agrees with the Company’s rate design methodology of reducing subsidies uniformly by 25%: “I think that's a rational and good way to distribute any increase, because it would reduce all subsidies by 25 percent. But doing this part of the settlement and returning [EDIT] credits to ratepayers on a uniform [cents] per kilowatt hour would enhance that subsidy reduction, and I believe that’s the way it was done in the DEP case.” (Tr. vol. 22, 146.)[7]

[7] *See* witness Phillips’ testimony in the DEP Rate Case, in Docket No. E-2, Sub 1219, of which the Commission took judicial notice in these proceedings pursuant to its Order dated October 26, 2020:

Based on the evidence in the record, and consistent with the way in which North Carolina EDIT was flowed back to customers in Docket No. E-7, Sub 1146, the Commission finds and concludes that unprotected EDIT and deferred revenue should be refunded to customers on a uniform cents per kWh basis as provided in the CIGFUR Stipulation and as illustrated in Pirro Second Settlement Ex. 9. In reaching this conclusion, the Commission gives great weight to the testimony of witness Pirro that continuation of a trend toward rate parity by reducing subsidy/excess levels would be desirable and that flowing back EDIT on a uniform cents per kWh helps balance out historical subsidization of the residential class by other customers.

Other Rate Design and Cost Allocation Issues

The remaining provisions of the CIGFUR Stipulation pertain to items the Company has agreed to either consider or propose in the future. The Commission notes that its finding that these provisions are just and reasonable as part of its overall approval of the CIGFUR Stipulation of course does not bind the Commission to approve the methodologies proposed therein or otherwise serve as precedent in future rate cases or other proceedings. In addition, the Public Staff and other parties are free to contest or endorse the cost allocation methodologies and rate design proposals the Company has agreed to make in future rate cases or other proceedings pursuant to the CIGFUR Stipulation just as they would be in the absence of these provisions.

The CIGFUR Stipulation provides that DEC and CIGFUR agree to meet prior to the Company's next general rate case to discuss potential cost of service methodologies that the Company may recommend for the purpose of allocating production and transmission costs. (CIGFUR Stipulation, § V.A.) In addition, the parties agreed that in its next rate case, DEC should file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes. (Id.) In this provision, DEC simply agrees to consider using the Summer/Winter Coincident Peak Method in its next rate case; DEC does not agree to recommend, support, or propose this method. (*See* Tr. vol. 12, 82-83.) Further, Summer/Winter Coincident Peak is just one method among many that the Company has

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> Q. . . . [D]o you know whether the Commission has previously approved a flowback of EDIT to DEP customers on a uniform cents-per-kilowatt hour basis?
>
> A. Yes, they have. It was, I believe, Docket E-2, Sub 1188 where they passed back more than $100 million on that method, and I think that order says it was previously done in a previous case on some state taxes in that same way.

(DEP Tr. vol. 14, 359.) *See also*, Order Approving Proposal and Requiring Filing of Revised Tariffs, Docket No. E-2, Sub 1188 (November 26, 2018) (approving DEP's request to reduce rates to reflect the reduction in the federal corporate income tax rate by implementing a 0.278 cents per kWh rate decrement applicable to all customers, but noting that the Commission's decision was based upon the facts and circumstances in that case and should not be considered precedential).

agreed to investigate prior to its next rate case (which is clear from the fact that in the same provision, the Company agrees to meet and discuss with CIGFUR more generally the potential methodologies the Company may recommend for allocating production and transmission costs in its next case). In addition, as discussed in Evidence and Conclusions for Findings of Fact Nos. 34-37, the Company has agreed to evaluate no less than six cost allocation methodologies pursuant to the Second Partial Stipulation. (*See* id. at 83.) Further, that DEC agreed to file the Summer/Winter Coincident Peak Method does not in any way bind the Company to use this method. As both witness Hager and witness Floyd testified, the Company routinely files multiple cost-of-service studies as part of its rate case Application (in this case, SCP, WCP, and SWPA), but obviously only recommends one. (*See* Tr. vol. 13, 83; Tr. vol. 19, 78-79.) And as witness Hager pointed out, Summer/Winter Coincident Peak is simply an average of two of the methods the Company already files – SCP and WCP. (*See* Tr. vol. 13, 106.)

The CIGFUR Stipulation also provides that in its next three general rate cases, the Company will propose to allocate distribution expenses using the minimum system method. (CIGFUR Stipulation, § V.D.) In the event the Commission orders a different approach for allocating distribution expenses, the Company may, but is not obligated to, propose the minimum system method. (*See* id.) As discussed in the Evidence and Conclusions in Support of Findings of Fact Nos. 34-37, the Commission finds that the Company's use of the minimum system method to allocate customer-related distribution costs is reasonable and appropriate for the purpose of allocating costs to the respective rate classes in this rate case. As such, pursuant to the CIGFUR Stipulation, the Company is obligated to propose the minimum system approach in its next general rate case. (*See* CIGFUR Stipulation, § V.D.) Along the same lines, DEC and CIGFUR agreed that in its next rate case, the Company will propose to allocate deferred GIP costs among the customer classes consistent with its distribution cost allocation methodologies proposed in this docket, including use of the minimum system method and use of voltage differentiated allocation factors for distribution plant. (CIGFUR Stipulation, § III.B.) The Commission takes no position as to whether minimum system method will be appropriate for DEC in the future, but recognizes that DEC has used the minimum system method for decades and has strongly advocated for this method anytime it has been challenged. The Company is certainly free to agree to continue to propose and support the minimum system method in the future if it so chooses, just as intervenors are free to challenge this method in the future if they so choose.

In the CIGFUR Stipulation, DEC has also agreed that in its next rate case, it will adjust its peak demand to remove curtailable/non-firm load, even if it does not call this load. (CIGFUR Stipulation, § V.B.) If the Commission approves this adjustment in the Company's next rate case, then DEC will propose use of this adjustment in its next subsequent rate case. (Id.)

The Public Staff suggested that this adjustment would be inappropriate for DEC. (Tr. vol. 18, 336-37; Tr. vol. 19, 80-82.) While witness Floyd acknowledged that he had previously supported this type of adjustment in Dominion's 2012 rate case in Docket No. E-22, Sub 479 (Sub 479 Case), he indicated that his support was based on the following factors: (1) Dominion had activated all of its DSM resources and interruptible loads at the time of its summer peak in the Sub 479 Case test year, but only activated a portion of those resources at the time of its winter peak, and thus, the relationship between the summer and winter peaks was distorted without the adjustment; and (2) Dominion relied upon the SWPA cost of service methodology in the Sub 479 Case, and therefore, even those customers who could contribute to reducing their peak loads could not avoid all production plant cost responsibility for the interruptible portion of their loads that was present in the other hours of the year, due to the average demand component of SWPA. (Tr. vol. 18, 337; *see also*, Tr. vol. 19, 80-82.) By contrast, he noted that DEC did not activate any of its DSM or interruptible resources at the time of the summer peak, so if DEC had made this adjustment in this rate case, customers who had their interruptible load removed from cost of service, whether they actually were called upon to interrupt or not, would avoid paying any production plant related costs for that same load, even though the load was present for the remainder of the test year. (Tr. vol. 18, 337.) Nevertheless, the Public Staff's position on the appropriateness of this adjustment for DEC was based on the test year and factual circumstances in this rate case, and this provision of the CIGFUR Stipulation does not apply to this rate case. (Tr. vol. 13, 83-84.) During cross-examination, witness Floyd and witness McLawhorn indicated that whether the Public Staff would oppose this adjustment for DEC in the future would depend upon the cost allocation methodology and whether the Company actually utilized its interruptible and DSM resources. (Tr. vol. 19, 81-82.)

Witness Phillips provided several reasons why, in his view, an adjustment to remove curtailable load may be appropriate. (*See* Tr. vol. 22, 139-40.) For example, he testified that if the Company has curtailable load, it does not need to build or buy capacity to serve that load, so it is correct to remove that load from the demand allocator. (*See* id. at 139-40.) Notwithstanding, he concluded that the points he raised need to be "discussed and hammered out. And we don't have a proposal before us today with testimony explaining it, and that's why I'm hesitant to prolong this, because I don't think this issue is before the Commission now." (Id. at 140.) As witness Phillips appropriately pointed out, this issue is not before the Commission in this case, and as the Public Staff witnesses testified, whether the Public Staff would support or oppose such an adjustment would depend on the facts and the circumstances of the particular case. DEC is free to propose and support this adjustment its next rate case, and the Public Staff and other intervenors are free to take any position they would like.

In § V.C of the CIGFUR Stipulation, the Company agrees that in its next two annual fuel cost recovery proceedings, it will propose the uniform percentage average bill adjustment methodology that was most recently approved by the Commission in the Company's 2019 fuel cost recovery proceeding. The Company is welcome to propose this methodology in its fuel cost recovery proceedings in 2021 and 2022, and the Commission will evaluate whether it is appropriate under the evidence in those cases.

CIGFUR witness Phillips provided testimony on a number of rate design topics, and recommended that DEC should offer a high load factor rate and allow existing load to receive service from Schedule HP in order to help mitigate the projected decline in industrial sales and customers. (Tr. vol. 22, 97, 115-16.) In the CIGFUR Stipulation, the Company agreed to explore: (1) a rate schedule targeted at high load users similar to

Duke Energy Indiana's HLF rate; (2) allowing customers to move existing load to the existing hourly pricing rate; and (3) an emergency demand response program similar to Southern California Edison's Time-of-Use Base Interruptible tariff. (CIGFUR Stipulation, § V.E.) The CIGFUR Stipulation provides that if the Company undertakes a comprehensive rate design process prior to the Company's next general rate case, this would be the proper venue for such consideration. (*See* id.) Further, if there is mutual agreement between CIGFUR and the Company on any of the terms of the above-referenced rates, and CIGFUR indicates that at least one of its members is willing to take service under such rates, the Company agrees to file said rates for Commission approval in its next rate case. (*See* id.) Again, this provision does not bind the Commission to rule in any way in future rate cases and does not even require the Company to propose a certain rate unless, through the comprehensive rate design process, it finds such a rate would be appropriate and it is able to reach agreement with CIGFUR on the terms of such a rate.

In summary, as witness Phillips expressed in his live testimony,

> The things that Duke agreed to present in a future case would be subject to review in the future case, and the Public Staff could comment on anything they disagree with at that time instead of now….All of the things that we asked for in the future are contingent on Commission approval…I don't think two parties can enter a settlement that tie the Commission's hands in a future case.

(Tr. vol. 22, 138-39.) Subsequently, in response to questioning by the Commission, witness Phillips testified that "[w]e understand that just because Duke proposes something, or CIGFUR, or anyone proposes something in the next general rate case, that the ultimate decision is with the Commission, and any party can write testimony or briefs and take a different position. We're just bringing out that we want Duke to continue this treatment that it's sound cost causation, and keep doing it." (Id. at 149.)

The Commission agrees with this testimony from witness Phillips that the Commission would not be bound to accept or approve any of the cost allocation or rate design matters it stipulated with CIGFUR to propose in future rate cases. Therefore, the Commission does not take any issue with these provisions of the CIGFUR Stipulation and approves them as part of its approval of the CIGFUR Stipulation as a whole.

Discussion and Conclusions

As with the Second Partial Stipulation, because the CIGFUR Stipulation has not been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject the CIGFUR Stipulation is governed by the standards set forth by the North Carolina Supreme Court in *CUCA I* and *CUCA II*.

The Commission gives significant weight to the testimony of DEC witnesses Hager and Pirro regarding the Company's support for the CIGFUR Stipulation.

As a result, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between CIGFUR and the Company during their settlement negotiations in an effort to appropriately balance the parties' positions. In addition, the Commission finds and concludes that the CIGFUR Stipulation was entered into by DEC and CIGFUR after discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute between the Company and CIGFUR in this docket. Finally, the Commission finds and concludes that the CIGFUR Stipulation is fair, reasonable, and in the public interest. As a result, the CIGFUR Stipulation is material evidence to be given appropriate weight in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 63

The evidence supporting these findings and conclusions is contained in DEC's verified Application and Form E-1, the testimony and exhibits of Company witnesses De May, Oliver and C. Barnes; NCJC et al. witness Howat; NCSEA and NCJC et al. witnesses Alvarez and Stephens; the NCSEA and NCJC et al. Stipulation, and the entire record in this proceeding.

On July 23, 2020, DEC filed the NCSEA and NCJC et al. Stipulation which resolves certain issues in this proceeding between the parties, including the appropriate rate of return and capital structure for setting rates in this proceeding, the Company's proposed GIP, and provides for shareholder contributions to the Helping Home Fund, collaboration on Low-Income EE/DSM Pilot programs, collaboration on a Tariffed On Bill Pilot Program, and agreement by the Company to publish a Distributed Generation Guidance Map and provide Hosting Capacity Analyses.

As the NCSEA and NCJC et al. Stipulation have not been adopted by all of the parties to this docket, as previously discussed in our discussion of the Public Staff Partial Stipulations, its acceptance by the Commission is governed by the standards set out in *CUCA I* and C*UCA II*.

The Commission credits the testimony of the Company, NCSEA, and NCJC et al. witnesses concerning the issues that are settled in the NCSEA and NCJC et al. Stipulation and finds and concludes that the NCSEA and NCJC et al. Stipulation is the product of the give-and-take negotiations between DEC, NCSEA and NCJC et al., in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers. The NCSEA and NCJC et al. Stipulation is, therefore, material evidence to be given appropriate weight in this proceeding.

As detailed below, there is ample evidence in the record to support all of the provisions of the NCSEA and NCJC et al. Stipulation, including those which have been contested by some intervenors. Accordingly, the Commission is fully justified in adopting the NCSEA and NCJC et al. Stipulation through the exercise of its own independent judgment, and finding and concluding through such independent judgment that the NCSEA and NCJC et al. Stipulation "is just and reasonable to all parties in light of all the evidence presented." CUCA I, 348 N.C. at 466. The Commission hereby adopts the NCSEA and NCJC et al. Stipulation in its entirety, and the conclusions as to the individual provisions of the NCSEA and NCJC et al. Stipulation are set forth more fully below.

Rate of Return and Capital Structure

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 24-30, as part of the NCSEA and NCJC et al. Stipulation, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. (NCSEA and NCJC et al. Stipulation, § 2.) Subsequently, DEC and the Public Staff entered into the Second Partial Stipulation which, among other things, stipulated to an ROE of 9.6%. The parties to the NCSEA and NCJC et al. Stipulation amended their agreement to recognize that if the Commission issues an order approving an ROE of 9.6%, the parties to the NCSEA and NCJC et al. Stipulation agree that the provisions of their respective agreements regarding ROE have been met. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 24-30, the Commission finds 9.6% to be a reasonable ROE for DEC and finds 52% equity and 48% debt to be a reasonable capital structure for DEC in this general rate case.

Grid Improvement Plan

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 31-33 and 65, as part of it settlement agreement with DEC, NCSEA and NCJC et al. support the approval of DEC's requested GIP deferral with certain conditions detailed therein, including a reservation of NCSEA and NCJC et al.'s right to review and object to the reasonableness of specific GIP costs in future rate cases. (*See* NCSEA and NCJC et al. Stipulation, § III.) In addition, the parties agreed to the extent DEC enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, NCSEA and NCJC et al. support such cost containment measure (Id.) As discussed in the Evidence and Conclusions for Findings of Fact Nos. 31-33 and 65, the Commission finds the GIP-related provisions of the settlements between the Company NCSEA and NCJC et al. supporting or not opposing GIP implementation, are reasonable and appropriate.

Helping Home Fund

As noted earlier, DEC witness De May testified that DEC is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship and that DEC wants to do even more for these customers, particularly those most in need, and are considering ways for the Company and its customer base to continue to be good stewards. (Tr. vol. 11, 860.) NCJC et al. witness Howat supported witness De May's commitment to addressing these affordability issues and underscored that electricity service is a necessity in present-day society. (Tr. vol. 17, 570.) Witness Howat stated that increased contributions to the Helping Home Fund would help address these affordability challenges faced by customers and would mitigate the impacts of a rate increase. (Tr. vol. 10, 133, 154-55; Tr. vol. 17, 588.) Witness

Howat testified that programs like the Helping Home Fund help low-income households have a higher likelihood of maintaining essential electric service. (Tr. vol. 17, 588.)

As part of the NCSEA and NCJC et al. Stipulation, the Company agreed to provide, in conjunction with DEP, an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million). (NCSEA and NCJC et al. Stipulation, § IV.) The Helping Home Fund is a program administered by the North Carolina Community Action Association and offered through a network of community action agencies that serve households in DEC and DEP service territories. (Id.) The Helping Home Fund program delivers weatherization services, heating and cooling system repairs, appliance replacements and critical health and safety repairs at no cost to DEC and DEP customer households at or below 200% of federal poverty guidelines. (Id; *see also "Evaluation of Duke Energy's Helping Home Fund," Advanced Energy,* (Oct. 15, 2017), Official Ex. vol. 17, part 5, 309 (Ex. JH-5).)

No intervenors took issue with this provision of the NCSEA and NCJC et al. Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the Helping Home Fund contributions are approved.

Low-Income EE/DSM

NCJC et al. witness Howat testified that low-income energy efficiency programs "provide the cornerstone of low-income energy security." (Tr. vol. 10, 132-33.) Witness Howat emphasized that energy efficiency programs are an important complement to affordable rate designs. (Id.) DEC witness De May agreed with witness Howat that development of new low-income energy efficiency programs are important steps towards improving affordability. (Tr. vol. 12, 37-38.) In addition, DEC witness C. Barnes testified that the Company understands that many customers have difficulty paying their energy bills and underscored the value in taking a collaborative approach to addressing these issues. (Tr. vol. 11, 63, 93.)

As part of the NCSEA and NCJC et al. Stipulation, the Company agreed to collaborate with NCSEA and NCJC et al. in designing low-income EE/DSM program pilots. (NCSEA and NCJC et al. Stipulation, § V.) Those program pilots will then be presented to the EE/DSM Collaborative participants listed in the Direct Testimony of Robert P. Evans, filed June 9, 2020 in Docket No. E-2, Sub 1252, along with the Company. (Id.) If a majority of the EE/DSM Collaborative participants support the program, the Company agreed to file for approval of the pilot programs in both North Carolina and South Carolina. (Id.) If the Company, NCSEA, and NCJC et al. agree on programs to file on a non-pilot basis, they agreed to file a joint petition with the Commission for approval. (Id.)

No intervenors took issue with this provision of the NCSEA and NCJC et al. Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the terms of the settlement regarding the Low-Income EE/DSM Pilot Program is approved.

Tariffed On-Bill Pilot Program

A tariffed on-bill program allows a utility to make energy efficiency investments at a participating customer's premises that are tied to the meter and recovered over time with a tariff on that customer's bill. (NCJC et al. Late-Filed Ex. No. 3, Attachment 3, 67.) Implementing a voluntary tariffed on-bill program is one of the recommendations of the Clean Energy Plan, developed by the Department of Environmental Quality in accordance with Governor Cooper's Executive Order 80. (Tr. vol. 16, 179.) The Commission has previously received testimony that the implementation of a tariffed on-bill program would not be cost effective until the Company's new customer information system was deployed. (*See*, Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, 33, Docket No. E-7, Sub 1192 (October 18, 2019).) Testimony in this proceeding criticized the Company for not proposing a tariffed on-bill program. (Tr. vol. 16, 574.)

The NCSEA and NCJC et al. Stipulation sets forth that the Company and NCSEA and NCJC et al. will examine a number of issues related to the implementation of a tariffed on-bill program. The Company has further agreed to file with the Commission a tariffed on-bill pilot program, if the parties to the stipulation agree on program terms, or a status report within 18 months. Thus, the NCSEA and NCJC et al. Stipulation contemplates that the tariffed on-bill pilot program will be implemented after the Company deploys its new customer information system, addressing concerns previously raised to the Commission.

No intervenors took issue with this provision of the NCSEA and NCJC et al. Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the terms of the settlement regarding the Tariffed On-Bill Pilot Program are approved.

Distributed Generation Guidance Map / Hosting Capacity Analyses

Hosting capacity is defined as the amount of distributed generation (DG) that can be accommodated on a distribution circuit without degrading reliability and power quality. (Tr. vol. 14, 43, Docket No. E-7, Sub 1146.[8]) A hosting capacity analysis is an analysis undertaken by a utility of each circuit to identify the maximum amount of DER that can be added without violating system constraints. (Id. at 42.)

Witness Oliver's testimony and exhibits clearly indicate that the projects comprising the GIP will increase the Company's hosting capacity. (*See* generally, Ex.s vol. 11.) While there is not universal agreement among the parties about how much the Company's hosting capacity will increase, no party disagrees with Witness Oliver's testimony that the GIP will increase the Company's hosting capacity. However, without guidance as to circuits and geographic locations where hosting capacity has increased,

[8] In its Order Establishing General Rate Case, Suspending Rates, Scheduling Hearings, and Requiring Public Notice, issued on October 29, 2019, the Commission took judicial notice pursuant to N.C.G.S. § 62-55 "of all evidence, decisions and other matters of record pertaining to coal combustion residuals (CCRs), Advanced Metering Infrastructure (AMI), and Power Forward in DEC's last general rate case, Docket No. E-7, Sub 1146[.]"

customers and DG developers cannot identify preferred locations for interconnection. Utilizing hosting capacity analyses to create DG guidance maps, or hosting capacity maps, will allow customers and DG developers to identify preferred locations for interconnection, streamlining the interconnection process through fewer delays and reduced uncertainty. (Tr. vol. 14, 45, Docket No. E-7, Sub 1146.)

The NCSEA and NCJC et al. Stipulation provides that the Company will preview a Distributed Generation Guidance Map to stakeholders through the interconnection Technical Standards Review Group (TSRG) and the Integrated System & Operations Planning (ISOP) stakeholder meetings before making hosting capacity analyses available for a representative sample of the Company's circuits in the future. While not initially included in the GIP proposal, Distributed Generation Guidance Maps are directly related to the GIP plan.

The NCSEA and NCJC et al. Stipulation also sets forth a process for the Company to integrate ISOP into its integrated resource planning process and for further stakeholder engagement in the development of tools and capabilities for ISOP implementation. While ISOP was included in the GIP, details of its integration into the integrated resource planning process and stakeholder engagement were not.

No intervenors took issue with this provision of the NCSEA and NCJC et al. Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the terms of the settlement regarding the Distributed Generation Guidance Map and Hosting Capacity Analyses are approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 64

The evidence supporting these findings and conclusions is contained in the Vote Solar Stipulation, DEC's verified Application and Form E-1, the testimony and exhibits of Vote Solar witnesses Fitch and Van Nostrand, and the entire record in this proceeding.

On July 9, 2020, DEC filed the Vote Solar Stipulation which resolves certain issues in this proceeding between the parties, including the appropriate rate of return and capital structure for setting rates in this proceeding, the Company's proposed GIP, and provides for Climate Risk and Resilience Planning through a working group.

As the Vote Solar Stipulation has not been adopted by all of the parties to this docket, as previously discussed in our discussion of the Public Staff Partial Stipulations, its acceptance by the Commission is governed by the standards set out in *CUCA I* and C*UCA II*.

The Commission credits the testimony of the Company and Vote Solar witnesses concerning the issues that are settled in the Vote Solar Stipulation and finds and concludes that the Vote Solar Stipulation is the product of the give-and-take negotiations between DEC and Vote Solar in an effort to appropriately balance the Company's need for rate relief with the impact of such rate relief on customers. The Vote Solar Stipulation is, therefore, material evidence to be given appropriate weight in this proceeding.

As detailed below, there is ample evidence in the record to support all of the provisions of the Vote Solar Stipulation, including those which have been contested by some intervenors. Accordingly, the Commission is fully justified in adopting the Vote Solar Stipulation through the exercise of its own independent judgment, and finding and concluding through such independent judgment that the Vote Solar Stipulation "is just and reasonable to all parties in light of all the evidence presented." CUCA I, 348 N.C. at 466. The Commission hereby adopts the Vote Solar Stipulation in its entirety, and the conclusions as to the individual provisions of the Vote Solar Stipulation are set forth more fully below.

Rate of Return and Capital Structure

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 24-30, as part of the Vote Solar Stipulation, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. (Vote Solar Stipulation, § 2.) Subsequently, DEC and the Public Staff entered into the Second Partial Stipulation which, among other things, stipulated to an ROE of 9.6%. The parties to the Vote Solar Stipulation amended their agreement to recognize that if the Commission issues an order approving an ROE of 9.6%, the parties to the Vote Solar Stipulation agree that the provisions of their respective agreements regarding ROE have been met. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 24-30 the Commission finds 9.6% to be a reasonable ROE for DEC and finds 52% equity and 48% debt to be a reasonable capital structure for DEC in this general rate case.

Grid Improvement Plan

As discussed in the Evidence and Conclusions for Findings of Fact Nos. 31-33 and 65, as part of it settlement agreement with DEC, Vote Solar supports the approval of DEC's requested GIP deferral with certain conditions detailed therein, including a reservation of Vote Solar's right to review and object to the reasonableness of specific GIP costs in future rate cases. (*See* Vote Solar Stipulation, § III.2.) In addition, the parties agreed to the extent DEC enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, Vote Solar supports such cost containment measure (Id. at § III.1.) Finally, DEC commits to develop potential pilot customer programs prior to the submission of the 2022 Integrated Resource Plan to optimize the capability of the GIP investments to support greater utilization of distributed energy resources. (Id.) As discussed in the Evidence and Conclusions for Findings of Fact Nos. 31-33 and 65, the Commission finds the GIP-related provisions of the settlements between the Company and Vote Solar supporting or not opposing GIP implementation, are reasonable and appropriate.

Climate-Resilience Planning

Vote Solar presented extensive evidence of the evolution of risk assessment in the utility, investment and finance, and insurance industries to include and incorporate the impacts of climate change and climate risk on the assets and operations of electric utilities. While still a nascent and evolving field, Vote Solar presented evidence of trends in other jurisdictions where evaluation of climate risk is becoming part of the regulatory review process and is being proactively incorporated into utility planning processes to address and mitigate foreseeable risks associated with climate change to the distribution and transmission grids of electrical utilities.

In § IV of the Vote Solar Stipulation, DEC agrees to convene a Climate Risk & Resilience Working Group (Working Group) that will assist in the development of models and analytical tools or techniques to study and integrate the effects of climate change into distribution and transmission system planning. The Working Group will also assist in developing an implementation plan based on the analytical tools developed that will be filed as part of the 2024 Integrated Resource Plan (IRP) proceeding, or in a proceeding otherwise designated by the Commission.

DEC will submit a scoping plan for the Working Group within sixty days of a final order and will provide notice to interested parties in North Carolina and South Carolina of the opportunity to participate in the Working Group. DEC will select and fund a third-party consultant with experience modelling climate-related impacts and will ultimately seek cost recovery in a future proceeding.

DEC and Vote Solar agree to work together to develop customer programs with resilience aspects, including customer-owned microgrids, residential customer-sited solar plus storage facilities, and demand response for control of certain programmable loads. Such programs have the potential to mitigate climate-related risks for the DEC and its customers and would be introduced prior to or concurrently with the DEC’s 2022 IRP filing.

No intervenors took issue with this provision of the Vote Solar Stipulation. Accordingly, the Commission finds and concludes that consistent with the terms of the settlement, and in light of all the evidence presented, the terms of the settlement regarding Climate-Resilience Planning are approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 65

The evidence supporting these findings and conclusion is contained in the Company’s verified Application and Form E-1, the testimony and exhibits of Company witnesses McManeus, Oliver, NCSEA and NCJC et al. witnesses Alvarez and Stephens, the Second Partial Stipulation, the Customer Group Stipulations, the Vote Solar Stipulation, the NCSEA and NCJC et al. Stipulation, and the entire record in this proceeding.

Prior to the evidentiary hearing, in addition to the Second Partial Stipulation discussed in Evidence and Conclusions for Findings of Fact Nos. 31-33, the Company entered into separate settlement agreements with several parties that filed testimony in opposition to its GIP proposals. These included Harris Teeter, CIGFUR, Vote Solar, the Commercial Group, NCSEA and NCJC et al. and are referred to herein collectively as the Intervenor Stipulations. Each of these settlements, as they relate to GIP program proposals, is discussed below.

Harris Teeter Stipulation

On May 27, 2020, DEC and Harris Teeter entered into the Harris Teeter Stipulation resolving some of the issues in this proceeding between the two parties. The Harris Teeter Stipulation provides, in pertinent part, that Harris Teeter supports the approval of a GIP deferral as requested by DEC in this docket. (Harris Teeter Stipulation, § 1.) Additionally, the Harris Teeter Stipulation specifies that to the extent that DEC enters into an agreement with other intervening parties agreeing to a cost cap or to otherwise limit the maximum allowed amount of DEC's GIP deferral, Harris Teeter supports such cost containment measures. (Id.) Further, the Harris Teeter Stipulation states that Harris Teeter is not prevented from taking any position in future cost recovery proceedings regarding the reasonableness of specific GIP program or subprogram costs. (Id.) In addition, DEC agreed that any GIP costs allocated to OPT-V customers would be recovered via demand charges. (Id. at § 2.)

CIGFUR Stipulation

On May 29, 2020, DEC and CIGFUR entered into the CIGFUR Stipulation resolving some of the issues in this proceeding between the two parties. The CIGFUR Stipulation provides, in relevant part, that for the purposes of settlement only and without taking a position on the appropriateness of the individual GIP programs or subprograms, CIGFUR supports the Company's request in this docket for approval to defer costs associated with the incremental GIP investments not included in this case and incurred over a three-year period for cost recovery consideration in future general rate cases. (CIGFUR Stipulation § III.A.) The CIGFUR Stipulation explains that because the three-year GIP contains estimates, CIGFUR's support for the GIP deferral will be subject to a reservation of its rights to review and object to the reasonableness of specific GIP program and subprogram costs in future rate cases. (Id.) The CIGFUR Stipulation also provides that to the extent that the Company enters into an agreement with other intervening parties agreeing to a cost cap or to otherwise limit the maximum allowed amount of the three-year GIP deferral, CIGFUR supports such cost containment measures. (Id.)

Additionally, the CIGFUR Stipulation provides that with regard to allocating the deferred GIP costs among the customer classes, in its next general rate case, the Company will propose to allocate these costs consistent with its distribution cost allocation methodologies as proposed in this Docket. (Id. at § III.B.) The CIGFUR Stipulation specifies that this includes use of the minimum system methodology and use of voltage differentiated allocation factors for distribution plant. (Id.) Moreover, the CIGFUR Stipulation states that assuming Commission approval, the Company agrees to use this methodology to allocate any GIP costs occurring during the three-year period for which it may seek cost recovery in future rate cases. (Id.)

Finally, the CIGFUR Stipulation states that for GIP costs incurred beyond the three-year period, nothing within the CIGFUR Stipulation shall be precedent for appropriateness of future deferrals or the allocation of deferred costs and these issues may be contested in future general rate case proceedings. (Id. at § III.C.)

The Commercial Group Stipulation

On June 1, 2020, DEC and an ad hoc group of commercial customer intervenors designated as the Commercial Group, filed the Commercial Group Stipulation in this proceeding. This settlement provides that pursuant to the agreement of the parties, the Commercial Group did not oppose (or specifically support) the Company's Grid Improvement Plan proposals in this case. (Commercial Group Stipulation at § 1.) The only caveat on this statement was an agreement that any GIP costs allocated to OPT-V customers would be recovered via demand charges. (Id. at § 2.)

Vote Solar Stipulation

On July 8, 2020, DEC and Vote Solar entered into the Vote Solar Stipulation resolving some of the issues in this proceeding between the two parties. The Vote Solar Stipulation provides, in relevant part, that Vote Solar supports the Company's request in this docket for approval to defer costs for investments in the ISOP, IVVC, SOG, DA, Transmission System Intelligence, DER Dispatch Tool, and the 44kV System Upgrade GIP programs and subprograms. (Vote Solar Stipulation, § III.1.) The Vote Solar Stipulation also provides that for all other GIP programs and subprograms, Vote Solar does not oppose the requested deferral accounting treatment. (Id.) The Vote Solar Stipulation further states that to the extent that the Company enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, Vote Solar supports such cost containment measures. (Id.) Finally, the Vote Solar Stipulation states that support for the GIP deferral will be subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases. (Id. at § III.2.)

Additionally, the Vote Solar Stipulation provides that the Company commits to develop potential pilot customer programs prior to the submission of the 2022 IRP to optimize the capability of the GIP investments to support greater utilization of DERs, including but not limited to customer-sited solar and/or storage facilities (e.g., net metering successor), microgrid systems that benefit and would be paid for by specific benefitted customers, and programmable and load controllable devices or appliances for use in residential and non-residential demand response programs. (Id.) The Vote Solar Stipulation specifies that if the Company and Vote Solar mutually agree that these programs are cost-effective and meet appropriate Commission requirements, the Company agrees to file such pilot programs for approval by the Commission, and Vote Solar agrees to support such approval by the Commission. (Id.)

The NCSEA and NCJC et al. Stipulation

On July 23, 2020, DEC and an intervenor group consisting of NCSEA and NCJC et al. filed the NCSEA and NCJC et al. Stipulation with the Commission in this docket. In that settlement, the parties agreed that a number of DEC's proposed GIP programs would "directly enable and support the greater utilization of distributed energy resources on the Company's system." (NCSEA and NCJC et al. Stipulation at § III.) The programs that the parties to this settlement agreed to specifically support on this basis were as follows: (1) ISOP; (2) IVVC; (3) SOG; (4) Distribution Automation; (5) Transmission System Intelligence; (6) DER Dispatch Tool; and (7) 44kv Line Rebuild. (Id.) With regard to DEC's other then-pending GIP programs, the intervenor group agreed not to oppose the requested deferral treatment. The settlement with this intervenor group also reserved their right to review and object to the reasonableness of specific GIP costs in future rate proceedings. Finally, as part of the agreement, DEC agreed that congestion relief would be primary criterion in planning and decision-making regarding future transmission and distribution investments. (Id.)

Discussion of Intervenor Stipulations

The Commission finds that the Intervenor Stipulations, as they relate to the Company's GIP related proposals, are the product of arm's length negotiations between parties who took contradictory positions on this subject in the pre-filed testimony of this proceeding. The Commission notes that, at least with respect to the programs eligible for deferral treatment, the provisions of the Intervenor Stipulations are constrained by the provisions of the Second Partial Stipulation with the Public Staff which identifies eight GIP programs eligible for deferral treatment. The Intervenor Stipulations, in combination with the Second Partial Stipulation, dramatically reduce the number of contested issues presented to the Commission for resolution with regard to proposed GIP deferrals by effectively eliminating the disputes between the settling parties and DEC reflected in the testimony of the various intervenor witnesses related to DEC's GIP proposals. Several of the settlement stipulations with the environmental and social justice intervenors also indicate support for the GIP settlement based upon a belief that such settlements will promote and support the transition to DER and renewable energy resources.

The Commission concludes, based upon all the evidence presented in this case and discussed herein, that approval of the settlement stipulations entered into between DEC and the intervenors identified above with respect to an agreed resolution of the Company's proposed GIP deferral request represents a reasonable and negotiated resolution of the GIP disputes in this docket that is supported, or not opposed, by several of the parties filing testimony on GIP issues in this proceeding. Accordingly, the Intervenor Stipulations represent material evidence of the appropriate resolution of this proceeding relative to GIP-related issues and they will be treated as such by the Commission.

Consequences of Failure to Authorize GIP Deferrals

The Commission is mindful that a decision not to allow the settled GIP programs to proceed with deferral accounting has its own consequences. The evidence of those consequences, provided primarily by DEC witness Oliver, are effectively uncontested. That evidence is that without deferral accounting treatment, DEC will be unable to pursue critical grid modernization activities on a programmatic basis and instead will have to approach them on an ad hoc basis when funds can be obtained in competition with all other capital needs of the company. (Tr. vol. 5, 50-51; Tr. vol. 6, 57-58.) According to the evidence on this issue, this will significantly slow the implementation of grid modernization and make it less efficient whereas allowing deferral treatment for the settled GIP programs gives DEC "the ability to do the programs in a much more cost-effective way, do it in a planned-out way, to bring the benefits to our customers much sooner." (Tr. vol. 6, 56.). We agree with witness Oliver's testimony on this point and find that bringing the benefits of the eight settled GIP programs to customers sooner and with greater efficiency - rather than later with less efficiency - is in the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witnesses Hager and Oliver; Public Staff witnesses Thomas and McLawhorn, and the entire record in this proceeding.

Public Staff witness Thomas testified that there is no new allocation factor proposed for GIP investments, and all GIP costs are expected to be allocated among customer classes according to the allocation factors that have historically been used for transmission and distribution expenditures. (Tr. vol. 17, 415.) He stated that, at this time, he is not recommending that GIP costs be allocated differently than traditional transmission and distribution spend. (Id. at 417.) However, witness Thomas believes that the issue is ripe for Commission consideration, particularly in light of the Commission's order requiring the Company to file testimony in its next general rate case regarding the benefits that distributed generators are receiving from DEC's system, estimating their share of related costs, and providing options for recovering these costs from distributed generators.[9] (Id.) He testified that if the Commission agrees that this issue merits further study, DEC's planned study of the impact of distributed generation could be expanded to require an evaluation of possible alternative methods of allocating GIP investments that provide primarily reliability benefits. (Id.)

Public Staff witness McLawhorn testified that the Public Staff's analysis of GIP indicates that benefits derived from some of the assets are disproportionally related to the way the GIP transmission and distribution plant is allocated. (Tr. vol. 18, 246.) According to witness McLawhorn, distribution plant, for example, is heavily weighted toward the residential class, while the benefits derived from the GIP investments in distribution plant are heavily weighted toward the general service and industrial customer classes. (Id. at 246-47.) He testified that he believes this is an area of cost allocation that warrants further analysis and recommended that the Commission require DEC to study the allocation of

[9] Order Approving Revised Interconnection Standard and Requiring Reports and Testimony, Docket No. E-100, Sub 101 (June 14, 2019).

GIP transmission and distribution investments/costs versus the benefits realized and report its findings to the Commission no later than the filing of its next general rate case. (Id. at 247.)

In her rebuttal testimony, Company witness Hager testified that the Company proposes that the investments associated with the GIP follow the same cost causation principles that are applied to the investments in the same FERC accounts as reflected in the cost of service study. (Tr. vol. 12, 222.) She noted that while she has not looked at these costs in particular, it is her opinion that "attempting to allocate ANY investment costs for ratemaking purposes based on perceived benefits realized by customers, as differentiated from cost causation to the utility, is likely to be very subjective and thus controversial." (Id. at 222-23.) She stated that one need look no further than witness Thomas's and witness Oliver's testimony to see that there are differing opinions on how to quantify customer benefits. (Id. at 223.)

When asked by the Public Staff what the harm would be of a study that could resolve or result in a better understanding of the issue, witness Hager indicated that she does not believe it is an effort that is "likely to yield fruit." (Id. at 299.) She said that the concept of allocating costs based on benefits has "so many downfalls" that to go forward with it would be a "waste of time." (Id.) She explained that while it is appropriate to look at the benefits in deciding which GIP projects to pursue and how to prioritize those projects (as the Company has done in its cost benefit analyses for GIP programs in this case), trying to allocate costs based on benefits is "very much a departure from traditional cost allocation methodologies." (*See* id. at 300.)

> We don't look beyond the meter to say what benefits those customers receive. I think if you start doing that, I think there's a real question of, you know, where do you stop? How do you measure those benefits? I think we'd all agree what we've heard in this hearing is that there's [sic] a lot of different opinions on what those benefits would be. I would suggest they change frequently. I think [there] would be lots and lots of different arguments on how to quantify those.

(Id. at 300-01.) For example, witness Hager noted that though reliability benefits can be most easily quantified for industrial and commercial customers, that does not mean there are not benefits for residential customers; rather, benefits to residential customers are just more difficult to quantify. (Id. at 301.) She pointed out that cost benefit analyses only measure a narrow aspect of the benefits of GIP programs and concluded that "benefits are convenient for the purposes of selecting projects, but I would suggest that they really don't have a place for the purposes of cost of service." (Id.)

In response to questioning from counsel for CUCA, witness Hager reiterated that it would not be productive to spend a lot of time and effort exploring an alternative cost of service methodology that is based on allocating benefits. (Tr. vol. 13, 36-37.) She stated that such an exercise would "depart from principles of cost causation" and "it's certainly not done within in the industry in any mainstream way." (Id. at 37.) Moreover, she described benefits as "very individualized" and "very difficult to measure," with any attempt to do so being "basically an estimate." (Id.)

In response to Commission questions, witness Hager pointed out that if one were to take the Public Staff's recommendation to "an extreme conclusion" and allocate all electricity costs based on benefits, "then you've completely upended the way that costs have been allocated in the past." (Id. at 108). She indicated that attempting to allocate costs based on benefits has the potential to create "artificial allocations based on things that are very, very difficult to quantify." (Id.)

As noted in Evidence and Conclusions for Findings of Facts Nos. 61-62, the Company has agreed to propose, in a future rate case, that deferred GIP costs be allocated among the customer classes consistent with its distribution cost allocation methodologies as proposed in this docket, including minimum system. (CIGFUR Stipulation, § III.B.) In the Company's last rate case, the Commission recognized that in light of substantial projected investment in grid modernization programs, "distribution system cost allocation among customer classes will take on heightened importance in future rate cases." (*See* 2018 DEC Rate Order, at 85.) Accordingly, in the 2018 Rate Order, the Commission directed the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes, recommendations, and alternative approaches, if appropriate. (Id.) Witness Hager testified that in the resulting Report on Minimum System,[10] the Public Staff concluded that continued use of the minimum system method was reasonable for the electric utilities for the purpose of cost allocation and did not propose any alternative methodologies. (*See* Tr. vol. 13, 80; *see also* Hager DEC Redirect Ex. 1, at 15-17.) In reaching this conclusion, the Public Staff reviewed the National Association of Regulatory Utility Commissioners "Electric Utility Cost Allocation Manual" published in January 1992 (NARUC Manual), which it stated "continues to be considered an important resource for the calculation and allocation of electric utility costs of service for regulatory commissions, consumer advocates, and parties before the Commission testifying on issues of cost of service and rate design." (Tr. vol. 13, 80-81; Hager DEC Redirect Ex. 1, at 4.)

Witness Hager acknowledged that the authors of the electric cost allocation manual published in January 2020 by the Regulatory Assistance Project (RAP)[11] – which presumably the Public Staff relies upon to make its recommendation relating to the study of allocating GIP costs based on benefits – suggest a different approach to aspects of cost of service allocation than the approach used in the NARUC Manual. (*See* Tr. vol. 12, 298.) However, she explained that "the manual which is put out by the Regulatory Assistance Project comes from a very specific viewpoint of wanting to encourage energy

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[10] Report of the Public Staff on the Minimum System Methodology of North Carolina Electric Public Utilities, Docket No. E-100, Sub 162 (March 28, 2019). (Hager DEC Redirect Exhibit 1.) Note that in that Report, the Public Staff reserved the right to develop a new or different position concerning minimum system in a future proceeding. (Id. at fn. 25.)

[11] Electric Cost Allocation for a New Era (January 2020). (Public Staff Pirro/Hager Cross Examination Exhibit 1.)

efficiency and distributed energy resources." (Id.) And therefore, the manual "favors policies and methods that would drive that." (Id.) She later noted that while RAP's dedication to a "clean, reliable, and efficient energy future" is certainly a laudable goal, it should not be captured in cost of service, which should be "focused on cost causation and how the electrons flow." (*See* Tr. vol. 13, 65.) She testified that cost of service "needs to avoid subjective aspects to the extent it can" and described it as "really more of a science." (Id. at 46.)

Witness Hager compared the revenue requirement as being the size of the pie that the Company is seeking to recover and the cost of service study as how the pie is sliced. (*See* id. at 31-33.) In the cost of service world, witness Hager explained, "[e]veryone wants a smaller piece of the pie . . . give my slice to that person. I'll take a smaller slice." (Id. at 33.) To that end, while intervenors have certain views as to how the pie is sliced based upon how a certain cost allocation methodology might benefit their constituents, the Company is essentially agnostic as to how the pie is sliced when it comes to cost allocation as long as it can recover all of its costs. (*See* id. at 31-33, 129-30.) Witness Hager agreed that the Company's primary motivation in proposing cost allocation methodologies is to allocate costs in a fair and equitable manner, according to longstanding cost allocation principles. (*See* id. at 129-30.) She explained that cost of service is supposed to be unbiased and is not intended to implement public policy: "I look at it as, you know, how do the electrons flow and what caused those electrons to flow in that manner." (*See* id. at 32.) She concluded, "I think all things being equal…the Company is just trying to do what it believes is fair and equitable and treats essentially all electrons equally." (Id. at 130.)

While the issue of how deferred GIP costs should be allocated got a fair amount to attention during the evidentiary hearing in this matter, the Commission need not address the appropriate cost allocation methodology in this case. The Commission will address recovery of deferred costs relating to GIP programs in the Company's next general rate case, and in that future rate case, the Commission will evaluate the Company's proposed allocation methodology, as well as any alternatives proposed by the Public Staff or other parties. Nevertheless, the Public Staff has asked the Commission to decide in this case that the Company should be required to study allocating costs relating to GIP investments based on benefits. The Commission gives great weight to the testimony of witness Hager that such an exercise would likely be highly subjective, imprecise, and controversial. As such, the Commission agrees with witness Hager that this type of study is not likely to be a productive or fruitful endeavor and therefore rejects the Public Staff's recommendation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 67

The evidence supporting these findings and conclusion is contained in the Company's verified Application and Form E-1, the testimony and exhibits of Company witness McManeus, Public Staff witness Boswell, and the entire record in this proceeding.

In the pre-filed Direct Testimony of Company witness McManeus, she explained that the Company had removed Test Period operating expenses and rate base amounts related to five hydro stations sold August 16, 2019. (Tr. vol. 11, 484.) The Commission approved the sale of the facilities and the transfer of the related certificates of convenience and necessity in Docket Nos. E-7, Sub 1181; SP-12478, Sub 0; and SP-12479, Sub 0. (Id.) The Commission also approved the establishment of a regulatory asset for the estimated loss on the disposition of the facilities. (Id.) In order to closely align the revenue requirement amount associated with the loss on the sale to the revenue requirement amount associated with ownership of the facilities, the Company proposes to amortize the estimated loss on the sale over a seven-year period. (Id. at 485.) In her Supplemental Direct Testimony, witness McManeus updated the adjustment, which was based on estimated values, to reflect final accounting entries related to completion of the sale. (Id. at 508.)

Public Staff witness Boswell recommends a 20-year amortization period on the deferred loss on the sale of the hydro assets which is the remaining depreciable life of the assets if they had remained in service. (Tr. vol. 17, 257.) Witness Boswell also noted that the cost benefit analysis provided by the Company in the Sub 1181 docket was based on 20-year costs to maintain and operate the facilities and in the Public Staff's testimony in that docket, the Public Staff had also recommended a 20-year amortization period. (Id.)

The Company opposes the Public Staff's recommendation arguing that its proposed 7-year amortization closely aligns with the amount of revenue requirement associated with the test period annual O&M expense and annual depreciation expense of the hydro units being sold, resulting in minimal change to existing rates. (Tr. vol. 11, 523.) Witness McManeus explained that the Company chose the proposed seven-year amortization period "by taking into consideration the costs related to these facilities that were in existing rates that need to be removed because the facilities are sold. And so we took into consideration what the amount that was being removed, and we chose an amortization amount that would roughly equal what was being removed." (Tr. vol. 15, 123.) In other words, she explained that the Company is removing some O&M, some depreciation, and some property tax of a certain amount for the hydro stations, and replacing it with the amortization of the loss, so that the amortization of the loss was about equal to the amount in existing rates for the facilities. (Id.) Further, witness McManeus testified that the Company "took a bit of guidance from the Commission's order in the hydro case [Sub 1181]" in arriving at its seven-year amortization recommendation. (Id.) She testified that in the Sub 1181 order, the Commission indicated that the amortization should begin when the sale was closed, and that the amortization amount should be equal to the depreciation expense. (Id. at 123-24.) The revenue requirement impact of the Company's recommendation of a seven-year amortization period is $3,249,000 (McManeus Supplemental Ex. 1, NC-3201, line 8) and the revenue requirement impact of the Public Staff's proposed 20-year amortization period is $1,140,000. (Boswell Second Supplemental and Stipulation Ex. 1, Schedule 3-1(e), line 7.) While witness McManeus acknowledged that amortizing the loss over seven years versus 20 years results in a higher revenue requirement, she pointed out that the return that the customer would pay over seven years would be a lesser amount than the return customers would pay over 20 years. (Id.) For the reasons noted by witness McManeus, and in particular her testimony that the 7-year amortization period was selected by the Company in an attempt to keep the impact on rates neutral, the Commission finds that a seven-year amortization period for the loss on the sale of these hydro stations strikes an appropriate balance between mitigating the impact to customers rates and providing a reasonable time period for the Company to recover its costs, and therefore, is just and reasonable and is approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 68-69

The evidence supporting these findings and conclusion is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witness Immel, Public Staff witness Metz, Sierra Club witness Wilson, Tech Customers witness Strunk, NC WARN witness Powers, and the entire record in this proceeding.

In the Application, DEC stated that since its previous rate case it has made capital investments in its coal fleet to meet environmental regulations to allow for the continued operation of active coal units and to allow certain coal units to burn natural gas. The Company stated that by enabling natural gas co-firing (dual fuel optionality or DFO), it can increase fuel flexibility and further reduce carbon emissions across the Carolinas to customers' benefit. (Application at 4-5, 7.) The Company also introduced an updated depreciation study reflecting revised retirement dates for certain coal units in the DEC fleet, which it stated reflects the industry's shift toward earlier retirement of coal units to manage carbon footprint risk as well as changing economic conditions and environmental regulations. (Id. at 8.)

In his direct testimony, Company witness Immel described the Company's fossil/hydro/solar (FHO) generation assets and provided operational performance results for those assets during the Test Period. (Tr. vol. 12, 53-54, 59-61.) Witness Immel also addressed major FHO capital additions DEC has completed since the previous rate case. Witness Immel explained that the Company has made significant investments in the coal fleet to meet environmental regulations to allow for the continued operation of active plants. (Id. at 56.) Witness Immel also discussed the DFO conversion projects at Cliffside Station and Belews Creek Unit 1, which he stated allows the Company to utilize the most cost-effective fuel and provides fuel flexibility for the benefit of customers. (Id. at 56.) Witness Immel testified that the Company prudently incurred all of these costs, and explained the key drivers impacting operations and maintenance (O&M) expenses during the Test Period and how DEC controls costs for capital projects and O&M. (Id. at 57.) Furthermore, he stated that these investments are used and useful in providing electric service, and benefit customers, as they have enabled DEC to continue to provide safe, efficient, and reliable service at least reasonable cost, and have reduced the Company's environmental footprint by adding state-of-the-art technology for reducing emissions and expanding the use of natural gas generation at a time when the natural gas market is providing low prices. (Id. at 57-59.)

In his Direct Testimony, Public Staff witness Metz discussed his review of DEC's capital additions to the FHO fleet, in which he looked at multiple aspects of capital spend to evaluate them for reasonableness and prudence, as well as whether the asset or result of the capital investment was used and useful. Witness Metz noted that his investigation included, in addition to reviewing prefiled direct testimony, an audit of specific expenditures, initial and follow-up discovery, teleconferences between and interviews with the Company and Public Staff, site visits, and review of the overall projects with Company management. (Tr. vol. 16, 660-61.) Witness Metz originally recommended an adjustment to remove the capital project costs related to the DFO conversion project at Belews Creek Station, but later reversed his recommendation in supplemental testimony (Id. at 661-64,680.) Notwithstanding, the Public Staff did not recommend any disallowance of the Company's request for recovery of its capital investments in FHO based on imprudence.

NC WARN witness Powers also recommended disallowance of the Company's costs for the DFO conversion projects. (Tr. vol. 16, 57.) Witness Powers claimed that the investments in these projects were not reasonable or prudent based on his assertion that DEC could have avoided them by relying on regional merchant combined cycle, hydroelectric plants, and the addition of battery storage at existing North Carolina solar facilities. (Id. at 51-57.) Witness Powers also stated that burning natural gas in steam boilers formerly fired on coal reduces the thermal efficiency of the combustion process, and compared the production cost at coal fired units to approximations of production cost at a combined cycle facility and hydroelectric unit. (Id. at 52-55.)

Sierra Club witness Wilson recommended disallowance of all of the Company's capital expenditures made during the time between the Sub 1146 case and the current case, based on her contention that the net value of each of the coal units was negative for the 2016-2018 time period, until DEC provides evidence of an analysis demonstrating the value of the investment done at the time the investment decision was made. (Tr. vol. 18, 150, 156-62.) Witness Wilson also claimed that the coal units only have positive net value in years with extreme weather, and recommended that DEC consider operating these units seasonally and only during months of peak demand to minimize losses to ratepayers until their retirement dates. (Id. at 162.) Based on her projected future energy value of the DEC coal fleet, and citing to the Georgia Public Service Commission (Georgia Commission) as having taken similar action, she also recommended that the Commission cap future capital expenditures intended to prolong the lives of these units and require DEC to obtain Commission approval of any expenditure that exceeds the cap before it can be recovered from customers. (Id. at 162-167.) Witness Wilson acknowledged the advancement of the probable retirement dates of certain units based on the Company's updated depreciation study. (Id. at 151). Witness Wilson stated that retirement of the entire coal fleet at once would likely lead to reliability issues in DEC's service territory (Id. at 166). Witness Wilson suggested that the used and useful standard could be interpreted to mean that, if there was a power plant construction project planned in a prudent manner, that operates at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee, that plant may be found prudent and used, but not economically useful. (Id. at 168.)

Tech Customers witness Strunk recommended disallowance of the incremental capital expenditures at Allen Units 4 and 5 and Cliffside Unit 5 between the Sub 1146 case and this case absent further justification of these investments. (Tr. vol. 16, 146.) Focusing on general coal trends and these units' capacity factors, he took issue with these investments in light of DEC's current proposal to accelerate the units' depreciable lives. (Id. at 149-51.) Witness Strunk also questioned the Company's prior decision not to retire these units early, but did not independently assess the retrospective economics of potential retirement decisions. (Id. at 151-53, 154-55.) Witness Strunk claimed that a primary reason for DEC's previous decisions regarding these units was the risk to investors of early retirement, although he recognized the reasonableness of this consideration. (Id. at 153-54, 156.) Witness Strunk acknowledged that much of the Company's recent coal-related investments involved compliance with coal ash regulations, but questioned whether earlier retirement of these units could have reduced the amount of these investments. (Id. at 159.) Witness Strunk suggested that, while he has not performed a detailed IRP-type analysis, DEC could replace a coal unit's energy and capacity with purchased power, surplus capacity, utility-scale renewables, and energy efficiency and demand response. (Id. at 160-61.)

In his rebuttal testimony, witness Immel responded to the testimony and recommendations of witnesses Metz, Wilson, Strunk, and Powers. Regarding witness Metz's recommended disallowance of the Belews Creek DFO project costs, he explained that the project is used and useful as it was placed in service on January 10, 2020, and began serving electric power to customers at that time. (Tr. vol. 12, 64-66.)

Witness Immel also described the voluminous information that DEC provided through discovery in this case, in addition to the evidence presented in his direct and rebuttal testimonies. (Id. at 66, 68-70.) Addressing arguments concerning the economic value of the coal fleet, he explained that such contentions fail to recognize the full picture of how DEC dispatches its coal fleet to maximize value for customers, and noted that witness Wilson's study did not appear to account for the requirement of day-ahead planning reserves. Witness Immel recognized that the capacity factors of the coal fleet are declining, but explained that DEC requires cycling resources, which operate at lower capacity factors, to provide reliable service to customers in periods of high demand. Witness Immel explained further that a coal unit will provide energy and capacity during the peak, and that if a needed coal unit is not online then the Company must start additional combustion turbines and/or purchase energy and capacity from the market, if capacity was available during such a time. (Id. at 73-74.)

Witness Immel also testified that witness Wilson's forward-looking analysis of the coal fleet is not a valid exercise for a general base rate case. (Id. at 75.) Witness Immel noted that witness Wilson did not explain how her proposed cap on future coal fleet investments would be determined, and clarified that these investments were not made to "prolong" the life of particular units but rather to maximize their remaining useful life. Witness Immel stated that the Company cannot recover such costs from customers unless and until the Commission permits it to do so. Finally, he clarified that estimates of future capital investments are not relevant to this proceeding. (Id. at 75-76.)

In response to witness Strunk, witness Immel testified that DEC studied the potential early retirement of Cliffside Unit 5 and Allen Station in 2016 and 2017, respectively, in order to make a timely decision regarding completion of upgrades at these units that were required by state and federal laws and regulations in order to maintain the units' environmental compliance and continue reliably serving customers. Witness Immel stated that, given the knowledge the Company had at the time, the studies did not show a compelling economic case for early retirement versus making the required capital investments. Witness Immel concluded that DEC therefore made the prudent decision in both cases to invest in these projects. (Id. at 70-71.) Witness Immel stated that the suggestion that DEC's previous retirement decisions were based primarily on the risk to investors disregarded the many factors considered by these studies, including needed transmission upgrades, replacement power needs, and timing of environmental compliance. Witness Immel also explained that net book value is not part of the economic analysis of early retirement but rather an additional separate consideration, and that the Allen Station retirement study on its own did not support early retirement. (Id. at 72, 104.) Witness Immel noted that DEC's subsequent decision, with the benefit of new and updated information about costs and risks, to propose accelerated depreciation of Allen Units 4 and 5 and Cliffside Unit 5 indicates that the Company is making prudent decisions based on the information available at the time. (Id. at 73.)

In response to witness Powers, witness Immel testified that the DFO project costs were reasonably and prudently incurred. Witness Immel noted that DEC conducted multiple cost-benefit analyses of these projects, which indicated that they would provide the Company and its customers economic value in the form of optionality with fluctuating coal and natural gas commodity prices, and resulting lower fuel costs for customers. Regarding efficiency, he explained that while thermal efficiency does decline with DFO, auxiliary load also decreases due to the elimination or reduction of the need for coal processing systems, ash systems, and wastewater treatment systems. (Id. at 77-78.) At the hearing, he testified in response to questions from NC WARN counsel that the overall efficiency of the generating unit is therefore minimally impacted. (Id. at 84-85.) Witness Immel also explained that the majority of the DFO investment at Cliffside Station was for Unit 6, which can run 100% on natural gas, and that the Company has already realized savings for customers from these projects. (Id. at 87, 112.) On redirect examination, he described the faster ramping capability that these projects provide, which in addition to helping DEC follow load throughout the day, also helps enable increasing levels of intermittent renewable generation, as well as savings related to startup costs. (Id. at 110-11.)

Finally, in response to suggestions that the Company could provide reliable electric service without the continued availability of its coal fleet through purchased power and renewable resources, witness Immel testified that no witness offered a credible and specific explanation of how DEC could have replaced the reliable generation provided by Belews Creek, Cliffside, or Allen Stations, with these resources. Witness Immel stated that neither witness Strunk nor witness Powers credibly challenged DEC's reasonable and prudent decisions to maintain operations at Allen Station and Cliffside Unit 5 and to invest in the DFO projects. (Id. at 78-79.)

At the hearing in response to questioning by Sierra Club counsel, witness Immel explained that in studying the early retirement of Allen Station and Cliffside Unit 5 in 2016, DEC assumed natural gas fired generation would replace these units because recent IRP filings indicated that was the most economical, dispatchable replacement resource. (Tr. vol. 92-93, 97-98.) Witness Immel also noted the importance of the voltage support provided by Allen Station during the study timeframe. (Id. at 98.) Witness Immel clarified that a significant portion of the coal fleet environmental investments would have been required regardless of whether the units were retired, and testified that even if a variance of such requirements was obtained for Allen Station, the units would not have been able to retire early due to transmission concerns. (Id. at 100-101.) Witness Immel noted that witness Wilson's analysis did not consider the capacity value provided by the coal units, even if they are not running. (Id. at 106-08, 118, 120.) Regarding witness Wilson's testimony regarding the profitability of the coal fleet during peak hours, he testified that in order to run during peak hours, DEC must maintain its units so that they can be available. (Id. at 120.) Addressing the changes in plans for the coal fleet from the time of the earlier retirement studies, to this case, and going forward, witness Immel stated that DEC continues to look for opportunities to retire coal in the most organized fashion with economic benefit to the customer, while meeting the state's and the Company's own emissions goals. (Id. at 121-122.) During redirect examination, he testified that the most recent retirement plans for these units support DEC's request for accelerated depreciation of certain units in this case. (Id. at 122-124.) Witness Immel also testified that no party presented any alternative that DEC could have chosen other than to make the investments in the coal fleet. (Id. at 124.)

In response to questions from counsel for the Company, witness Wilson agreed that as DEC transitions away from reliance on coal, it must do so while continuing to meet its obligation to provide safe and reliable electric service to customers. (Tr. vol. 18 at 176.) Witness Wilson acknowledged that her study of the economic value of the coal fleet did not analyze what DEC should have done with the information available to it at the time it incurred the costs to maintain these units, did not evaluate what replacement alternatives the Company should have chosen instead of making the investments, and did not identify any particular investment DEC should not have made. (Id. at 177-79.) Witness Wilson testified that she was not aware of the North Carolina standard for challenging prudence that requires a party to identify specific instances of imprudence and provide a prudent alternative. (Id. at 179.) With regard to her testimony on the "used and useful" standard, she could not identify any state commission that had adopted her interpretation of that standard. (Id. at 183.)

Witness Wilson agreed that some of the coal fleet environmental investments were required whether or not the units continued to operate, and that if additional environmental projects in order to continue to run those units had not been made, DEC would have had to shut the units down. (Id. at 187-88.) Witness Wilson testified that she did not analyze whether shutting the units down was a feasible path DEC could have chosen and continued to meet its service obligations. (Id. at 188-89.) When asked to illustrate her testimony that retiring all of the units immediately would likely result in reliability issues, she stated that "the lights … could potentially go out," and noted that retiring all of the coal units would not be sufficient to meet peak load plus a required reserve margin. (Id. at 189.)

Witness Wilson acknowledged that North Carolina uses a historical test year, updated through a certain time period, to examine reasonableness and prudency of costs. (Id. at 184.) With regard to the case she cited in support for her future investment cap proposal, she agreed that the Sierra Club did not join the stipulation approved by the

Georgia Commission, and that nonsigning parties' recommendations in that case were specifically denied. (Id. at 185-86.)

Witness Wilson agreed that the results of the 2016 Allen Station retirement study indicated that DEC would have incurred greater costs by retiring the station early than by making the investments required to continue to run it, but stated without further explanation that she objected to a number of the input assumptions made in the study. Witness Wilson stated that her analysis did not look at the need for replacement capacity for any of the coal units if they were to shut down. Witness Wilson testified that she did not mention the Allen study in her testimony, analyze the data provided in the study, or use any of the information DEC provided through discovery to conduct a retirement study for any of the coal units. (Id. at 197-00.)

In response to questioning by Commissioner Hughes regarding how to reconcile her testimony that retirement of the entire coal fleet would lead to reliability issues with her recommendation to categorically exclude all costs of the coal fleet, witness Wilson testified that her recommendation was to exclude the capital costs until the Company could provide economic analysis showing that the units were cost effective for customers. (Id. at 205.)

Discussion and Conclusions

Based on the entire record in this proceeding, the Commission finds and concludes that the costs associated with the Company's investments in its coal fleet were reasonably and prudently incurred and should be recovered. The Commission further finds and concludes that Sierra Club's recommendation to limit the Company's future investments in its coal units should not be adopted. Finally, the Commission finds and concludes that the costs for the Belews Creek Unit 1 DFO project are properly included in this case as used and useful.

When setting just and reasonable rates, the Commission must determine whether costs incurred by the utility were prudently incurred, which involves an examination of whether the utility's actions, inactions, or decisions to incur costs were reasonable based on what it knew or should have known at the time the actions, inactions, or decision to incur costs were made. DENC Order at 121; Harris Order at 14 (if needed: Order Granting Partial Increase in Rates and Charges, *Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Rates and Charges*, No. E-2, Sub 537, at 14 (N.C.U.C. Aug. 5, 1988), *rev'd in part on other grounds and remanded*, *Utils. Comm'n v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989) (Harris Order)). Challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives; and (3) quantify the effects by calculating imprudently incurred costs. DENC Order at 121-122; Harris Order at 14-15.

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production if they dispute an aspect of the utility's prima facie case. *State ex rel. Utils. Comm'n. Intervenor*

Residents of Bent Creek/Mt. Carmel Subdivisions, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Intervenor Residents*) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses . . . ."). If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility, in accordance with N.C.G.S. § 62-134(c).

The Commission gives substantial weight regarding the prudency of the costs of DEC's investments in its coal fleet to the prefiled and hearing testimony of Company witness Immel. Witness Immel explained in detail how the Company prudently determined that these investments were needed to maintain DEC's remaining active coal units to continue to provide safe, reliable, and cost-effective electric service to customers. A significant portion of these costs were required under environmental law or regulation regardless of whether the Company continued to run the units. A large portion of the remaining costs were incurred to maintain compliance with environmental requirements to continue to operate the units, and no party has offered concrete, specific evidence to contradict DEC's determination that it needed to continue to operate these units to serve customers. Regarding the DFO projects, witness Immel presented convincing evidence in rebuttal and at the hearing regarding the rationale for these investments, which are already resulting in savings for customers.

No intervenor has met the burden of production to challenge the Company's coal fleet investments. Sierra Club witness Wilson's recommended disallowance, as she admitted, is not specific to any particular cost, nor does Sierra Club offer any prudent alternative that DEC could have chosen rather than to make these investments. Witness Wilson in fact testified that retiring the coal fleet all at once would likely result in reliability issues but did not identify any other alternatives available to the Company. Tech Customers witness Strunk and NC WARN witness Powers direct their disallowance recommendations to particular units, but other than the DFO projects do not identify specific costs as being imprudently incurred. In addition, the alternatives suggested by these parties—merchant generation purchases, solar or hydroelectric generation, demand side management—are not supported by any evidence suggesting these were feasible options for the Company. No witness conducted an independent analysis using the information available at the time the Company's investment decisions were made to present evidence supporting a finding that DEC could have made another prudence choice. The evidence demonstrates that the Company made the best investment decisions it could with the information available at the time. The evidence also supports our conclusion that DEC is making needed investments to maximize the remaining useful life of its coal fleet, at the same time as it is moving away from relying on coal, as evidenced by its request in this case to reduce the depreciable lives of certain units and convert other units to have the capability to run on natural gas. The Commission agrees that as DEC transitions away from coal, it must do so in a manner that allows it to continue to reliable serve customers, and concludes that these investments were made consistent with that service obligation.

Moreover, the Commission finds persuasive witness Immel's rebuttal of witness Wilson's economic value analysis, which did not consider either the capacity value provided by DEC's coal fleet or how the Company dispatches its system as a whole on a daily basis. The Commission agrees with DEC that isolating costs invested in and the value of energy produced by a particular station on an annual basis does not accurately represent the value of the coal fleet; as witness Immel showed, even units with declining capacity factors are needed during times of high demand. For similar reasons, and because DEC must still invest in a unit to keep it available during high demand periods, the Commission does not find witness Wilson's recommendation that the Company consider operating its units seasonally to be reasonable. Finally, the Commission does not accept witness Wilson's interpretation of the term "useful" in the used and useful standard. Her reading contemplates finding an asset not to be useful when it was planned prudently and was impacted by changes outside the utility's control, which is not an interpretation that has been adopted by this Commission. On the contrary, if an expenditure does support and provide service to customers, those costs are "used and useful." Sub 1146 Order at 259.

Finally, witness Wilson qualified her disallowance recommendation on the contention that DEC did not present evidence of the value of the investments at the time they were made. However, as witness Wilson's hearing testimony made clear, she ignored evidence in the form of the 2016 Allen Station retirement study pertaining directly to this issue. As shown by witness Immel's prefiled and live testimony, including his testimony regarding the volume of data DEC provided to the Public Staff and intervenors in support of coal fleet investments, the Company conducted exhaustive studies of continued investments in Allen Station and Cliffside Unit 5, and of the DFO projects, and relied on the results of those studies to proceed with the investments it is seeking to recover. The Commission therefore concludes that Sierra Club's contention regarding a lack of evidence is unfounded, as DEC has demonstrated the reasonableness and prudence of incurring these costs and, as discussed above, no party has presented concrete evidence otherwise.

The Commission also declines to accept witness Wilson's recommendation to limit the Company's future investments in its coal fleet. Such a limitation is not necessary, as the Company cannot recover any future capital investments before seeking and obtaining the Commission's approval in a future proceeding. Further, as witness Wilson recognized, North Carolina uses a historical test year as the basis for evaluating just and reasonable rates, which is not consistent with a prospective limit on capital expenditures.

Finally, based on witness Immel's rebuttal testimony and witness Metz's supplemental testimony, the Commission finds and concludes that DEC's costs associated with the Belews Creek Unit 1 DFO project were used and useful for purposes of this proceeding and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

The evidence supporting this finding and conclusion is contained in the Company's verified Application and Form E-1, the testimony and exhibits of DEC witness Capps, Public Staff witness Metz, and the entire record in this proceeding.

In his direct testimony, Company witness Capps described DEC's nuclear generation assets and capital additions to the nuclear fleet made to enhance safety, address regulatory requirements, and preserve performance and reliability of these plants throughout their extended life operations. (Tr. vol. 11, 730, 732-35.) Witness Capps testified that these capital additions and enhancements are used and useful in safely and efficiently providing reliable service to DEC customers and position the Company to maintain the high levels of operational safety, efficiency and reliability reflected in the fleet's performance results. (Id. at 735.) Witness Capps also discussed key drivers impacting nuclear O&M costs, including inflationary pressure on labor and materials, and the Company's strategy for mitigating that pressure. Witness Capps noted that customers will continue to benefit from the strong performance of DEC's nuclear fleet through lower fuel costs. (Id. at 730, 736-37.) Witness Capps also testified to how the Company controls for capital projects and O&M using a rigorous cost management program and through outage optimization. (Id. at 735-38.) Witness Capps described DEC's current status with respect to compliance with Nuclear Regulatory Commission (NRC) requirements. (Id. at 738-39.) Finally, he discussed the high performance of the Company's nuclear fleet during the Test Period and the steps DEC has taken to increase efficiencies in nuclear operations. (Id. at 740-43.)

Public Staff witness Metz testified regarding his review of DEC's capital additions to the nuclear fleet, in which he looked at multiple aspects of capital spend to evaluate them for reasonableness and prudence, as well as whether the asset or result of the capital investment is used and useful. Witness Metz noted that his investigation included, in addition to reviewing witness Capps' pre-filed direct testimony, an audit of specific expenditures, initial and follow-up discovery, teleconferences between and interviews with the Company and Public Staff, and review of the overall projects with Company management. (Tr. vol. 16, 660-61.)

No party recommended any disallowance of the Company's request for recovery of its capital investments in its nuclear fleet based on unreasonableness or imprudence.

Based on the foregoing, the Commission finds and concludes that the costs associated with the Company's investments in its nuclear generating fleet were reasonably and prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 71

The evidence supporting this finding and conclusion is contained in the verified Application and Form E-1 of DEC, the testimony and exhibits of DEC witnesses De May and Spanos; Public Staff witnesses McCullar, Boswell, and Metz; and the entire record in this proceeding.

Company witness Spanos introduced Spanos Ex. 1, the depreciation study filed in this docket (Depreciation Study) prepared by Gannett Fleming Valuation and Rate Consultants, LLC. (Tr. vol. 12, 132.) As explained by witness Spanos, the Depreciation Study included updates to estimates of final plant depreciation costs for steam, hydraulic, and other production plants, as well as updated forecasted generation plant retirement dates. In addition, witness Spanos noted that the Depreciation Study incorporates the full decommissioning cost values from the Decommissioning Cost Estimate Study (Decommissioning Study) prepared by Burns and McDonnell Engineering Company, Inc. (Burns & McDonnell) and reviewed in Docket No. E-7, Sub 1146. The Decommissioning Study included estimates for final decommissioning costs at steam, hydraulic, and other production plants.

The updated depreciation rates for various fossil and hydro plants reflect changes in the probable retirement dates to align with current licenses, industry standards, or operational plans due to aging technology, assumptions regarding future environmental regulations, or new planned generation. (Spanos Ex. 1 at iii.) In addition, the Depreciation Study incorporates generation assets that have been placed in service since the last study. (Spanos Ex. 1 at iii.) As witness Spanos explained, estimates for costs related to coal ash pond closures are not included in the net salvage estimates, and therefore not included in depreciation rates. (Tr. vol. 22, 208.)

Public Staff witness McCullar also made recommendations related to depreciation expense. Witness McCullar recommended several adjustments to the Company's proposed depreciation rates including adjustments to future terminal net salvage costs (also known as decommissioning and dismantlement costs), and to other production plant interim net salvage percentages. Witness McCullar also recommended a longer average service life for AMI meters and a different net salvage percentage for on distribution account. (Tr. vol. 16, 615.) Finally, at the direction of witness Boswell, witness McCullar calculated depreciation rates using the retirement dates for Allen and Cliffside Unit 5 from the previous depreciation study. (Tr. vol. 16, 625.)

The Commission's discussion and resolution of issues raised by witnesses McCullar, Boswell, and Metz are discussed below.

Estimated Terminal Net Salvage Costs

Burns & McDonnell conducted the Decommissioning Study for DEC in 2017, which formed the basis for DEC's terminal net salvage cost estimates. Witness McCullar proposes that this Commission continue the use of the 10% contingency for future "unknowns" approved in Docket No. E-7, Sub 1146. (Tr. vol. 16, 603-04.) In response to witness McCullar's recommendation, witness Spanos explained why a 20% contingency is appropriately included in DEC's Decommissioning Study and why it is necessary that costs must be escalated to the date of retirement. (Tr. vol. 22, 179-92.)

The Need for Contingency

The Company's Decommissioning Study included a 20% contingency to cover unknowns. As Company witness Kopp testified in Docket No. E-7, Sub 1146, contingency costs are necessarily included in the Decommissioning Study to account for unspecified but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and demolition activities. (2018 DEC Rate Order at. 170-71.) Furthermore, past experience with costs incurred in the Carolinas by the Company for the decommissioning and demolition of the Cape Fear, H.F. Lee, Sutton, Robinson, and Weatherspoon plants were approximately 11% higher than the Burns & McDonnell estimates, inclusive of contingency. (Id. at 171.) Such past experience demonstrates the importance of contingency to the decommissioning cost estimate.

Public Staff witness McCullar recommended continued use of a 10% contingency factor, as approved by the Commission in Docket No. E-7, Sub 1146. (Tr. vol. 16, 604.)

At the hearing of this matter, witness Spanos explained the basis of his 20% contingency recommendation in this case compared to DEC's 10% factor in its prior rate case:

> Based on what we have learned since the last time in other scenarios where contingencies are – have been included, we've seen that 20 percent contingency has become more appropriate than the 10 percent. So – and utilized in my depreciation study we went back to the 20 percent, because it was more appropriate given the additional information we have in the industry.

(Tr. vol. 22, 257.) Witness Spanos further noted that "based on what we have found over the two years since this particular study was performed and what we incorporated in the depreciation study in this particular case for Duke Carolinas, we've learned in those two years that contingency estimates have been understated." (Id. at 259.)

The intent of adding the contingency is to ensure that decommissioning activity is fully funded at the point of retirement. Furthermore, the Decommissioning Study does not, and cannot, assume that some intervening event like the sale of a generating plant will avoid the future cost of decommissioning. Regardless, there are substantial costs required to shut down a facility whether or not demolition occurs, and contingency is a necessary component of those costs. Finally, the 20% contingency recommendation is consistent with other studies that Burns & McDonnell prepared for utility clients across the United States including Duke Energy affiliate companies, several of which have been approved by other Utility Commissions.

In the Company's last general rate case, the Commission approved a 10% contingency factor. (2018 DEC Rate Order at 172.) There, witness McCullar recommended a 0% contingency. (Id. at 170.) Nevertheless, the evidence presented by the Company established the importance and necessity of including contingency. Nevertheless, the evidence presented by the Company established the importance and necessity of including contingency. Further, even with 20% contingency there remains risk that the cost incurred by DEC for decommissioning and demolition may actually run higher than the Burns & McDonnell estimate inclusive of contingency.

In light of all of the evidence, the Commission finds and concludes that the 20% contingency factor proposed by the Company is just and reasonable and appropriate for use in this case. Contingency represents a real cost that is anticipated to be incurred on the project and using 20% will help increase the likelihood that decommissioning activity will be fully funded at the point of retirement.

Cost Escalated to the Date of Retirement

It is important to recover the service value of the Company's assets by determining the net salvage costs that will be incurred in the future. As DEC witness Spanos explained, using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts, each year over the life of the Company's plant. (Tr. vol. 12, 146.) This approach is consistent with the Federal Energy Regulatory Commission Uniform System of Accounts (USOA), which specifies that the cost of removal is the actual amount paid at the time the transaction takes place. (Tr. vol. 22, 187.) As such, including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. (*See* 2018 DEC Rate Order at 173.) In developing decommissioning cost estimates, it is necessary to escalate those estimates to the time period in which the cost is expected to be incurred. (2018 DEC Rate Order at 173.)

Witness McCullar testified that net salvage estimates for decommissioning the Company's power plants are escalated to the date of final retirement, consistent with the 2018 DEC Rate Order. (Tr. vol. 16, 605.) Confusingly, however, witness McCullar proceeded to discuss the concept of escalation and appeared to advocate instead for only escalating costs to the year 2023. (Id. at 610-11.) Witness McCullar testified that she selected 2023 because it "would inflate the terminal net salvage costs to the level of the dollars collected from the ratepayers for the time period the rates set in this proceeding are expected to be reasonable." (Id. at 610.) Witness McCullar contended that it would be unreasonable to collect inflated costs of removal in current dollars because it imposes too much risk on ratepayers due to the significant period of time over which the inflation is estimated. (Id. at 607.) Additionally, Witness McCullar noted that four other jurisdictions have removed the escalation of estimated future terminal net salvage costs. (Id. at 611-12.)

As explained by Witness Spanos, the Commission reviewed this concept in Docket No. E-7, Sub 1146 and determined that "the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted." (2018 DEC Rate Order at 175; Tr. vol. 22, 180.) The Commission also concluded that estimating net salvage as the future cost to retire an asset is consistent with sound depreciation practices and authoritative texts. (2018 DEC Rate Order at 174; Tr. vol. 22, 180.) Specifically, the Commission cited the National Association of Regulatory Utility Commissioners' *Public Utility Depreciation Practices* for the principle that "[n]et salvage is the difference between gross salvage that will be realized when the asset is disposed of and the costs of retiring it." (2018 DEC Rate Order at 174; Tr. vol. 22, 180.) The Commission also cited Wolf and Fitch, another highly regarded authoritative depreciation text, for the position that inflation is appropriately a part of the future cost of net salvage. (2018 DEC Rate Order at 174; Tr. vol. 22, 189-90.) In his testimony, Witness Spanos provided the following passage from Wolf and Fitch:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.

(Tr. vol. 22, 189.) Wolf and Fitch also make clear that inflation is part of the future cost of net salvage. Witness Spanos pointed out that Wolf and Fitch state the following:

> Negative salvage is a common occurrence. With inflation, the cost of retiring long-lived property, such as a water main, may exceed the original installed cost.

(Id. at 189.) Additionally, with respect to intergenerational equity, Witness Spanos noted that Wolf and Fitch state that:

> The accounting treatment of these future costs is clear. They are part of the current cost of using the asset and must be matched against revenue. While the current consumers would say they should not pay for future costs, it would be unfair to the future users if these costs were postponed.

(Id. at 189-90.) Finally, Wolf and Fitch also argue against a present value or current value concept. Witness Spanos provided the following excerpt from Wolf and Fitch:

> Some say that although the current consumers should pay for the future costs, the future value of the payments, calculated at some reasonable interest rate, should equal the retirement cost. Studies show that the salvage is often "more negative" than forecasters had predicted.

(Id. at 190.) Accordingly, Commission precedent, authoritative texts, and sound depreciation practices all support escalating terminal net salvage costs to the date the costs are expected to be incurred rather than some artificially foreshortened date.

While witness McCullar claims four other jurisdictions removed the escalation of estimated future terminal net salvage costs, none of the cases witness McCullar cited change the fact that the Commission has already decided this issue in Docket No. E-7, Sub 1146. (Id. at 185.) As witness Spanos explained, of the four cases witness McCullar cites, one is a settlement agreement and two are from more than a decade ago. (Id. at 185.) Since that time, a number of power plants have been retired and decommissioned

– many prior to being fully depreciated and without full recovery of terminal net salvage. (Id. at 185.) Accordingly, the cases witness McCullar cites are not particularly relevant to the instant proceeding. (Id. at 185.) Moreover, in Docket No. E-7, Sub 1146, the Commission found that the Company's approach to net salvage is used by the vast majority of regulatory jurisdictions. (Id. at 185.); 2018 DEC Rate Order at 175.) Specifically, the Commission stated that:

> The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method.

(2018 DEC Rate Order at 175; Tr. vol. 22, 186.) North Carolina is one of those jurisdictions that use the traditional method. Because of this fact, the Commission concludes that the cases witness McCullar cites are in the minority and should not be afforded any weight in this proceeding. (Tr. vol. 22, 186.)

Finally, the Commission previously found witness McCullar's approach to estimating terminal net salvage to be deficient. (Id. at 182.) In the 2018 DEC Rate Order, witness McCullar challenged the inclusion of the full future net salvage cost in depreciation and instead proposed to include only estimates of net salvage costs at current cost levels. (Id. 180.) As witness Spanos explained above, the Commission already reviewed this concept in Docket No. E-7, Sub 1146 and did not find witness McCullar's arguments persuasive. (Id. at 181.) In the 2018 DEC Rate Order, the Commission stated the following:

> Witness McCullar's approach is not supported by sound depreciation methods and would likely result in the under recovery of net salvage costs over the life of the asset. To that end, other state utility commissions have rejected witness McCullar's alternative approach as unsupported. For example, in a recent case before the Washington Utilities and Transportation Commission (WTC), witness McCullar advanced similar arguments against the escalation of terminal net salvage costs along with other recommendation related to depreciation. In rejecting the recommendation, the WTC noted that Public Counsel and witness McCullar provided no response to the critique that witness McCullar's approaches were not supported by authoritative accounting literature. The WTC found witness McCullar's net salvage proposal "[v]ague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions.

(2018 DEC Rate Order at 175 (footnotes omitted); Tr. vol. 22, 182.)

Considering all the evidence, the Commission finds and concludes that the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.

Mass Property Future Net Salvage

Net salvage estimates are expressed as a percentage of the original cost retired. (Id. at 182.) The method for determining the estimated net salvage percent depends on the type of property. (Id. at 183.) For power plants, the estimate is typically based on a decommissioning study, with additional net salvage incorporated for interim retirements. (Id.) For mass property accounts such as those for transmission and distribution plant, net salvage estimates are based in part on statistical analyses of historical net salvage data. (Id.) In this case, the statistical net salvage analyses incorporate the Company's actual historical data from 2003 through 2018, and considers the cost of removal and gross salvage ratios to the associated retirements during the 16-year period. (Tr. vol. 22, 143.)

Witness Spanos, in his depreciation study, recommends a net salvage percentage of negative 15% for Account 366, Underground Conduit. Witness McCullar recommends a future net salvage percent of negative 10% for Account 366, Underground Conduit. (Tr. vol. 16, 615.) Witness McCullar expressed concern with the Company's historic net salvage ratios calculated in the Depreciation Study. (Id. at 617-18.) Specifically, witness McCullar took issue with using a net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator. (Id. at 617.) Witness McCullar explained that due to inflation, the amounts in the numerator and denominator of the net salvage ratio are at different price levels. (Id. at 618.) Witness McCullar noted that five other jurisdictions have adopted future net salvage percentages that recognized the inflated dollars included in the historic net salvage ratio and adopted future net salvage percentages that recognize the time value of cost of removal due to inflation. (Id. at 618-21.)

In response, witness Spanos testified that witness McCullar's proposal is not consistent with the Commission's decision in Docket No. E-7, Sub 1146 and is unsupported by the record. (Tr. vol. 22, 181-82.) Witness McCullar supports her treatment of Account 366 by arguing against including future inflation in net salvage estimates. (Id. at 182.) As witness Spanos previously testified, the Commission has already decided against witness McCullar's position on this concept and found that the Company's approach was widely supported. (Id.) Overall, while witness McCullar's proposal for Account 366 does not have as significant an impact as her proposals for other accounts, she does not provide any statistical basis for her proposal. (Id. at 181-82.) The only analytical method witness McCullar provides in support of her proposal is a comparison of the net salvage costs included in the proposed depreciation rates to the amount of net salvage DEC has incurred, on average, over the past five years. (Id. at 191.) This type of analysis performed by witness McCullar does not provide a reasonable basis to estimate net salvage. (Id. at 191-92.) Additionally, NARUC and Wolf and Fitch do not support witness McCullar's approach for mass property accounts. (Id. at 192.) In fact, the Company is unaware of any authoritative texts that support witness McCullar's analysis. (Id.) Witness Spanos also notes that witness McCullar adopted this backward looking “recent history” approach for calculating net salvage only with regard to Account 366 and not to other property accounts. (Tr. vol. 23, 70.)

At the hearing of this matter, witness Spanos testified extensively that relying solely on recent historical data, as witness McCullar does for her mass property Account 366 recommendation, is inappropriate. (Tr. vol. 22, 261-63.)

> So in each category depending on the assets and on what you learned from the Company and doing studies within the industry, you’re able to come up with the most appropriate net salvage percentage that would incorporate not only the overall but also the most recent as well as what’s expected in the future. Because the net salvage percent that you determine is what we expect to happen going forward, so we can’t just focus on the past.

(Tr. vol. 22, 262.) In this regard, witness Spanos also testified that conduit is not typically an asset that is removed upon retirement and that this further supports a more negative net salvage value as proposed by the Company. (Id. at 264.) Witness Spanos was also asked on cross-examination about the net salvage calculation in an Atmos Energy rate proceeding in Kansas in which witness McCullar testified. (Public Staff Spanos Cross-Examination Ex. 1.) This testimony did not undermine witness Spanos’ position on net salvage, however, because it was clear from the face of the order in that proceeding that the Kansas Commission explicitly rejected a proposed negative salvage calculation based on a “recent history” approach similar to that offered by witness McCullar in this case. (Id. at ¶54.)

Considering all of the evidence, the Commission finds and concludes that the Company’s proposed future net salvage for mass property Account 366, Underground Conduit is just and reasonable, appropriate for use in this case, and is adopted.

Other Production Plant Interim Net Salvage Percent Production Accounts

The purpose of DEC’s Depreciation Study was to determine the annual depreciation accruals related to plant in service for ratemaking purposes and the appropriate average service lives and net salvage percentages for each account. (Tr. vol. 12, 134.) The estimated future net salvage is part of the annual depreciation accrual, which is credited to the reserve to cover the estimated future net salvage costs. In this case, the Depreciation Study supported a future interim net salvage percent of negative 6% for other production accounts, except for rotable parts at combined cycle plants. (Tr. vol. 16, 193.) As witness Spanos explained, he established an interim net salvage percent on an account basis and then performed the appropriate calculation in order to get the appropriate weighted interim net salvage, excluding Account 343.1. (Tr. vol. 12, 144-45.) The net salvage estimates were based on an analysis of historical cost of removal and salvage data, expectations with respect to future removal requirements, and markets for retired equipment and materials. (Tr. vol. 12, 144.)

Public Staff witness McCullar proposed the continued use of a 0% interim net salvage value for accounts 342, 343, 344, 345, and 346. (Tr. vol. 16, 4.) In this regard, witness McCullar testified that for some accounts, the annual accrual amount that would be accrued for estimated net salvage is several times the annual amount DEC actually incurs for net salvage. (Id. at 613-14.) Witness McCullar indicated that the historical analysis has been a positive $6,404,164 per year for the last three years and a positive $7,593,793 per year for the last five years. (Id. at 613.) As a result, witness McCullar took the position that DEC does not need to collect interim removal costs from ratepayers for these accounts, since it has more than recovered interim removal costs in its booked gross salvage. (Id. at 613-14.)

In response, witness Spanos noted that data since Docket No. E-7, Sub 1146 supports a negative interim net salvage value for other production accounts. (Tr. vol. 22, 193.) Witness Spanos explained that in the two years since the previous depreciation study, DEC has incurred $1,450,843 in cost of removal and received $45,163 in gross salvage. (Id. at 194.) Therefore, DEC should be permitted to collect interim removal costs since the cost of removal has exceeded gross salvage. (Id. at 195.) Additionally, because interim net salvage has been 0% for these accounts, these costs were not recovered over their service lives. (Id.) Witness Spanos predicted that negative salvage will, on average, continue to be negative going forward. (Id.)

In the case of other production plant, it is critical to understand all of the components of the historical data. As witness Spanos testified, the combustion turbines in modern combined cycle generating plants are highly efficient modern machines that require routine replacement and refurbishment of various components, including assets such as turbine blades and transition nozzles. (Id. at 196.) Witness Spanos explained that the net salvage for these “rotable parts” differs significantly from other components of a combined cycle plant. (Id. at 196.) Because rotable parts are regularly refurbished, they typically experience positive net salvage whereas other components of a combined cycle plant typically experience negative net salvage. (Id. at 195.) Witness Spanos posited that the positive net salvage for the other production accounts in previous years was likely due to positive net salvage for rotable parts. (Id. at 194.) As witness Spanos described further, while DEC’s previous depreciation study provided a separate net salvage analysis for rotable parts, these assets were not accounted for separately from the balance of Account 343, Prime Movers. (Id. at 195.) As a result, the specific demarcation between rotable parts and other components in the historical data was not apparent. (Id. at 195-96.) However, in the time since the previous depreciation study, DEC has accounted for rotable parts in a separate subaccount. (Id. at 196.) Witness Spanos observed that the non-rotable parts accounts have experienced negative net salvage, which is typical for these types of assets and should be expected going forward. (Id. at 196.)

In light of all of the evidence presented, the Commission finds and concludes that the negative 6% interim net salvage value proposed by the Company is just and reasonable based upon the evidence presented in this case. As witness Spanos appropriately explained, it is necessary to rely upon not only statistical analysis but informed judgment as to the assets being evaluated.

15-Year Service Life for AMI Meters

DEC requested a 15-year depreciation life for AMI meters. As explained by witness Spanos, a 15-S2.5 survivor curve was recommended by DEC for AMI meters. (Id. at 197.) This estimate was consistent with the manufacturer's recommendation for the physical life of the AMI meters and accounted for alternative reasons for retirement such as damage or obsolescence. (Id.)

Public Staff witness McCullar recommended a 17-year service life for AMI meters. (Tr. vol. 16, 615.) Witness McCullar testified that a 17-year life is in the middle of the manufacturer's range, is a reasonable estimate based on the manufacturer's expected life of the AMI meters, and is fair to the Company and the ratepayer. (Id.)

In response, witness Spanos pointed out that the Commission approved the 15-year service life for AMI meters in the 2018 DEC Rate Order. (Tr. vol. 22, 196.) DEC used a 15-year average service life in its previous depreciation study in Docket No. E-7, Sub 1146. (Id. at 196.) The 2018 DEC Rate Order adopted the depreciation rates proposed by DEC, except for certain depreciation rates discussed in the decision. (Id. at 196.) As witness Spanos explained, because the 15-year average service life was not specifically identified and modified in the 2018 DEC Rate Order, the 15-year average service life was adopted by the Commission. (Id. at 196-97.) Moreover, DEC's cost-benefit analysis for AMI meters was based on a 15-year average service life and the Commission had specifically requested that such analysis include the "cost of replacing AMI meters at the end of their 15-year useful life." (2018 DEC Rate Order at 117; Tr. vol. 22, 197.)

On cross-examination by Public Staff counsel on his direct testimony, witness Spanos further bolstered the reasonableness of a 15-year average service life for AMI meters by indicating that this period is the most common service life used for this type of asset in the industry and based on the type survivor curve most appropriately reflects the manufacturer's expectations. (Tr. vol. 12, 174.)

Witness McCullar has not provided any new evidence in the instant case that supports changing the 15-year average service life approved by the Commission. Witness Spanos noted that witness McCullar's arguments are almost identical to those she presented in Docket No. E-7, Sub 1146 that were not adopted by the Commission. (Tr. vol. 22, 197-98.) Additionally, witness McCullar simply took the mid-range of the manufacturer's life without considering issues like technological obsolescence. In that regard, witness McCullar made no attempt to distinguish the type of asset, which is a critical consideration when there is limited historical experience.

In light of all the evidence, the Commission finds and concludes that the Company's request to establish a 15-year average service life for AMI meters is just and reasonable and appropriate for use in this case.

Life Spans of Allen and Cliffside Unit 5

Since the last depreciation study, DEC changed the life spans of Allen Units 4 and 5 and Cliffside Unit 5 to be shorter than currently approved. DEC witness De May explained that "[a]s part of our strategy to reduce our reliance on coal, we have taken a fresh look at the viability of several of our coal-fired plants and have concluded that making shifts in the expected remaining depreciable lives of some of our coal-fired assets is a reasonable action to take now, while we continue to monitor the changing industry landscape and impacts of markets forces." (Tr. vol. 11, 859.) As witness Spanos testified, DEC intends to retire Allen Units 4 and 5 in 2024 and Cliffside Unit 5 in 2026. (Tr. vol. 22, 198.) The new life span for Allen is 67 years and the new life span for Cliffside Unit 5 is 54 years. (Tr. vol. 12, 141.) Witness Spanos incorporated the shortened life spans into the Depreciation Study and recommended depreciation rates using these retirement dates. (Tr. vol. 22, 198.) As explained by witness Spanos, the revised life spans are reasonable because, in recent years, original life spans for steam production facilities have been shortened due to unit efficiencies and environmental regulations. (Tr. vol. 12, 141.)

Public Staff witness McCullar calculated depreciation rates using the retirement dates from the previous depreciation study. (Tr. vol. 16, 625.) Witness McCullar explained that Public Staff witness Boswell directed McCullar to use the original retirement dates for Allen and Cliffside Unit 5. (Id. at 625.)

Public Staff witness Boswell recommended that witness McCullar restore the depreciation rate of Allen and Cliffside Unit 5 to the depreciation rate approved in Docket No. E-7, Sub 1146 for two reasons. (Tr. vol. 17, 245.) First, witness Boswell noted that although DEC stated that it intends to retire Allen and Cliffside Unit 5, it has not done so. (Id. at 245.) Second, Public Staff has consistently recommended that depreciation rates be set at the original retirement date of the plant. (Id. at 245.) Thereafter, at the physical date of retirement, any remaining net book value is placed into a regulatory asset account and amortized over a reasonable period, to be determined in a future general rate case. (Id. at 245.)

Additionally, Public Staff witness Metz took issue with evaluating the early retirements of Allen and Cliffside Unit 5 in the current proceeding. While witness Metz did not dispute the accelerated retirements of the units, he recommended that the retirements of Allen and Cliffside Unit 5 be reviewed in DEC's Integrated Resource Plan (IRP) proceeding. (Tr. vol. 16, 671.) Witness Metz acknowledged that the IRP does not solely focus on the economics of early generation retirements but nonetheless suggested that it was a more appropriate forum to evaluate early retirements than a general rate case. (Id. at 672.)

In response, witness De May stated that while, today, the Company's coal plants are critical to serving load and, in some cases, to system integrity support, the end of their useful lives is rapidly approaching. (Tr. vol. 11, 892.) As such, since expected retirement dates are accelerating, it is appropriate to prepare for this by likewise accelerating the depreciation of the Company's coal fleet. (Id.) Witness Spanos testified that the USOA requires that depreciation recover the costs of an asset over its service life. (Tr. vol. 22, 198.) Recovering costs after an asset is retired results in intergenerational inequity because future customers, who will not receive service from the retired asset, are forced to bear the costs for an asset that is already retired. (Id. at 198-99.) Witness Spanos explained that Public Staff's proposal will result in intergenerational inequity because it will result in DEC recovering a portion of the costs of Allen and Cliffside Unit 5 after they are retired. (Id. at 200.)

Witness Spanos also rebutted Public Staff witness Boswell's justifications for Public Staff's proposal. Witness Spanos explained that DEC is not required to physically retire Allen and Cliffside Unit 5 prior to determining depreciation rates. (Id. at 200.) For the purposes of determining depreciation, DEC cannot wait until Allen and Cliffside Unit 5 are retired to determine their service lives because the costs need to be recovered over the lives of the generating facilities. (Id.) Accordingly, witness Boswell's first justification for using the original retirement dates does not comport with the USOA or generally accepted depreciation principles. (Id.) Additionally, witness Boswell's argument that Public Staff has consistently advocated for setting depreciation rates at the original retirement date of the generating facility, and after physically retiring the facility, placing any costs into a regulatory asset account, is inequitable. (Id. at 200-01.) Witness Spanos correctly pointed out that any of the costs placed into a regulatory asset account and amortized over a given period will be recovered after Allen and Cliffside Unit 5 are retired. (Id. at 201.) Therefore, Public Staff's proposal will result in intergenerational inequity. (Id.) Witness Spanos acknowledged that use of a regulatory asset may be required in some cases, such as instances when the date of retirement is close to the date of a filed rate case. (Id.) However, the accelerated retirement dates of Allen and Cliffside Unit 5 are four years or more from the test year in the Depreciation Study and, as such, there is sufficient time to recover the costs of these plants over their service lives. (Id.)

At the hearing of this matter, witness Spanos reiterated his belief that principles of depreciation dictate spreading the remaining undepreciated value of the retiring plants over their remaining useful lives and that the Public Staff's preference for using outdated depreciation rates and then amortizing any unrecovered balance was both contrary to fundamental principles of depreciation and would result in intergenerational inequity. (Tr. vol. 22, 281-82.) Witness Spanos also emphasized the matching principle in defending his preference for restated depreciation rates for the retiring Allen and Cliffside plants. "I'm focusing on the matching principle which comes right from the Uniform System of Accounts, which is to match the utilization of the asset with the recovery of the asset. So, in this particular scenario, when we're talking about production facilities, the utilization of the asset is up to the probable retirement date or date they actually retire the asset, and recovery should match that." (Id. at 285.)

Witness De May testified that few things are as foreseeable now as the end of coal-fired generation in North Carolina and we are asking the Commission to approve its proposal to continue to address it. (Tr. vol. 11, 893.) According to witness De May, no one will want to deal with the issue of unrecovered book values down the road while simultaneously constructing replacement generation, so let's deal with it now while there is still time. (Id.)

In light of all of the evidence, the Commission finds and concludes that the shortened life spans of Allen and Cliffside Unit 5 should be incorporated into the Depreciation Study and used to set the depreciation rates. The Public Staff has failed to justify the use of retirement dates from the 2018 DEC Rate Order. Prudent depreciation practices and the USOA support the retirement of Allen Units 4 and 5 in 2024 and Cliffside Unit 5 in 2026 because this will result in DEC recovering the costs of the generating facilities over their service lives. In this case, recovering the full costs of Allen and Cliffside Unit 5 over their shortened service lives will prevent future customers from paying for an asset that is already retired and of which they did not receive service. In sum, adopting DEC's shortened retirement dates for Allen and Cliffside Unit 5 will prevent intergenerational inequity.

Conclusion

In light of all of the evidence presented, the Commission finds and concludes that the depreciation rates proposed by DEC in this case, which are based on the revised Depreciation Study included as Spanos Ex. 1 and the Decommissioning Study reviewed in Docket No. E-7, Sub 1146, are just and reasonable, fair to both the Company and its customers, and therefore are approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 72-74.

The evidence supporting these findings and conclusions is contained in the Company's verified Application and Form E-1, the evidence, orders and other matters of record in Docket No. E-7, Sub 1146 and Docket No. E-2, Sub 1142, late-filed exhibits, motions and Commission orders in this docket, and the testimony and exhibits of the following expert witnesses: DEC witnesses Bednarcik, Wells, Williams, Bonaparte, Lioy, Doss, Reilly, and Spanos; Public Staff Witnesses Junis, Maness, Lucas, Garrett, and Moore; AG witness Hart; Sierra Club witness Quarles; and CUCA witness O'Donnell.

The testimony and exhibits regarding DEC's CCR costs are voluminous, and the Commission has carefully considered all of the evidence and the record as a whole. Based on the Commissions consideration of the complete record in this case and for the reasons discussed further below, the Commission finds and concludes that the Company's CCR costs incurred from January 1, 2018, through January 31, 2020, were prudently and reasonably incurred.

Introduction and Background

DEC seeks in this rate case a total of $378 million (on a North Carolina retail basis) in coal ash basin closure costs, consisting of (a) actual costs of closure activities performed during the period from January 1, 2018 through January 31, 2020, all of which were incurred as a result of changes in the law with which the Company must comply, and all of which have been deferred by order of the Commission, and (b) financing costs incurred during the deferral period through July 2020. Pursuant to the "spend/defer/recover model" outlined in DEC's last rate case, the Company's investors, both debt and equity, supplied the funds for these costs (CCR Costs). As a rate mitigation measure, DEC proposes to bring these costs into rates over a five-year amortization period beginning with the date new rates go into effect. DEC proposes further that it earn a return upon the unamortized balance, at its authorized weighted average cost of capital. Should the return be disallowed, the net result would be the equivalent of a forced interest-free loan by the Company to its customers, an outcome manifestly unfair and confiscatory to the Company and its investors.

DEC requests that this Commission afford the same rate treatment it afforded to the Company in its last rate case.[12] The Company's overarching proposal focuses on (1) recovery "of" the coal ash costs the Company seeks in the current case (i.e., $378 million), along with (2) a return "on" those costs as they are brought into rates during the amortization period. The Company contends that recovery both "of" and "on" the incurred costs is warranted under the facts, the law, and the framework articulated in its 2018 Rate Order. As such, the Company through various witnesses in this case establishes that since the last rate case, the Company and its investors providing the capital to finance CCR remediation investments have acted upon the explicit rules of the road established by our prior rate order.

Many of these issues raised by intervenors in this case were litigated in the Company's last rate case discussed in this Commission's 2018 Order. For example:

- The Commission thoroughly considered the Company's "historical"[13] coal ash management practices, including their conformance to industry standards (2018 Order at 208.);

- The Commission thoroughly considered the uncertainty prevalent prior to the enactment of CAMA and the CCR Rule and the impact that uncertainty had upon the Company's decision and timing for taking actions at all of its ash basins. As this Commission comprehensively addressed in the prior rate case, regulatory certainty was needed to close the Company's ash basins, to establish the level of cost to be borne by customers, and to avoid credible arguments of gold-plating (2018 Order at 301-02);

- On three prior occasions, including in the Company's last rate case, this Commission has also considered the Public Staff's "equitable sharing" theory of cost disallowance, which the Commission emphatically rejected (2018 Order at 272-83);

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[12] Docket No. E-7, Sub 1146, which was decided by the Commission's June 22, 2018 Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction (2018 DEC Rate Order, or, simply, 2018 Order).

[13] "Historical" meaning prior to the changes in law wrought by the promulgation of the Federal CCR Rule in 2015, as well as the passage by the North Carolina General Assembly of the Coal Ash Management Act (CAMA) in 2014 and amendments to CAMA in 2016.

- The Commission has also exhaustively evaluated the propriety and effect of the Asset Retirement Obligation (ARO) accounting employed by DEC to account for its CCR expenditures (2018 Order at 284-288, 289-90); and

- Finally, the Commission has determined in its 2018 DEC Rate Order that the "spend/defer/recover" model employed by the Company in connection with its coal ash expenditures, entitles DEC to receive a return on such costs during both (1) the period during which those costs were deferred, and (2) the amortization period during which the previously deferred costs were brought into rates (2018 Order at 288-92).

Although parties in this case disagree as to whether new facts or evidence illuminating any of these issues was adduced in the current docket, a close evaluation of the "New" evidence from DEC, in its rebuttal case, supplemented and added more detail to evidence the Company presented in the prior case, primarily as a result of Intervenors raising the same issues that the Commission had already dealt with in the prior case. For example, the testimony of Company witness Marcia Williams brought to the Commission the perspective of a former EPA regulator, who led the EPA office that produced one of the major historical studies proffered by intervenors as "evidence" of the Company's historical imprudence, the 1988 EPA Report to Congress (1988 Report, Joint Ex. 13). Witness Williams testified that the 1988 Report *validated* the Company's historic ash management practices. As she noted, in the 1988 Report EPA concluded that no change was necessary to then-current coal ash waste management practices, inasmuch as those practices "appear[ed] adequate for protecting human health and the environment." (Joint Ex. 13 at 7-11.) And, as witness Williams also noted, EPA in crafting its 1988 Report was well aware that then-current waste management practices included, particularly in the Southeastern United States, unlined ash ponds. She noted that the 1988 Report found that these ponds

> [R]arely included the use of liners or leachate collection and that most facilities managing CCR did not have groundwater monitoring. The report found that 80 percent of CCR was disposed on the land (i.e., in surface impoundments, landfills, or other land-based units). Of the 483 surface impoundments in use at the time, only 45 were known to be lined while 303 were unlined and the liner status of 135 were unknown. In EPA's Region IV, which includes North Carolina, only 3 of the 195 surface impoundments were lined, while 153 were unlined and the liner status of 39 were unknown.

(Tr. vol. 27, 92-93.)

In the Company's prior case and after a full trial on the merits, the Commission adjudicated these contentions and found as facts both that "[a]t least since the 1950s, standard industry practice, particularly in the Southeastern United States, has been reliance on coal ash basins" (see 2018 DEC Rate Order at 208), and that as the 1988 Report itself indicated "'until recently, most surface impoundments and landfills used for utility waste management have been simple unlined systems.'" (Id. at 267.) Even as late as 2010, when EPA proposed its CCR Rule, witness Williams testified that according to the EPA 74% of existing units were unlined, and 40% of "new" (meaning constructed during the 1990s or thereafter) units were unlined. (Tr. vol. 27, 267.) The Company did not construct any coal ash basins after 1982, and all of its basins were unlined, in accordance with standard industry practice at the time of their construction. Yet intervenors' presentation ignores these already-adjudicated facts, and forces the Company to prove them all over again.

In this case, Intervenors ask the Commission to deny cost recovery on the basis of "fault"-based concepts, like "culpability." This is yet another aspect of Intervenors' re-litigation approach. The Commission presented a detailed critique of the "fault" based and tort-like disallowance theories proposed in the Company's prior case. (2018 DEC Rate Order, at 260-65.) The Commission held that its

> [D]uty is not to determine liability to and assess damages for torts committed by management or injury to the environment or to receptors of contaminants. Environmental regulators and courts of general jurisdiction are the appropriate arbitrators of those disputes. DEC's unlined impoundments at issue operated pursuant to environmental permits as wastewater treatment facilities by DEQ or its predecessor. That agency's statutory mandate is environmental protection and would be the agency to rectify breaches of a duty of due care, if any, such as that advocated by certain Intervenors in this case. The issues before this economic regulatory tribunal is imprudence -- who should bear the remediation costs, the utility stockholders or its customers and on the basis of what justification.

(Id. at 261.) Noting further that Intervenors equated lack of due care to management imprudence, the Commission stated that no one had cited to it any authority "to support the theory that, in determining the recovery through utility rates, costs of environmental remediation incurred by management to comply with the express requirements of environmental regulators, management decisions should be assessed against a standard of due care." (Id.) That observation is still true.

Cost recovery under North Carolina law is regulated by the Commission under the prudence standard. Prudently incurred costs associated with service to customers are recoverable.[14] Such costs include financing costs – the cost of money – upon prudently

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[14] The requirement that costs be associated with service belies the Public Staff's argument that many different types of costs are "shared" between shareholders and customers. For example, the Public Staff points to costs of senior management in a utility holding company. (See Tr. vol. 26, 121-22.) Such costs may well be "shared" but prudence, imprudence, or even "fault" have nothing to do with the sharing. Rather, because senior management's duties are split between separate utilities – or even between regulated and unregulated entities – only a portion of them are necessary to support service by any specific utility. And, of course, costs must also be "known and measurable" (2018 DEC Rate Order, at 258.) Here, as in the Company's prior case, no party has questioned whether CCR Costs are "known and measurable." Finally, costs must be "reasonable" in size, but in the context of this case (as in DEC's prior case, see 2108

incurred costs funded by the Company and its investors and deferred by order of the Commission in advance of being brought into rates, especially when they are brought into rates over time as a mitigation measure to reduce the impact of increased rates upon customers. Costs that are not prudently incurred are not recoverable. There is no room in such an analysis for tort-like "fault" concepts, and those concepts have no place in cost recovery under North Carolina law.

Legal Framework: Prudence and Industry Standards

Legal Framework: Prudence and Industry Standards

The legal framework regarding cost recovery is long-established, and was well articulated by the Commission in the 2018 DEC Rate Order. First, the operating principle underlying rate regulation generally is that the utility's reasonable and prudently incurred costs are recoverable in rates. (2018 Order at 257-58.) Second, under the evidentiary presumptions governing cost recovery the entirety of the utility's costs is deemed to be reasonable and prudent, unless challenged by an intervenor. (Id. at 259-62.) Third, if costs are challenged, the Commission must assess their prudence. (Id. at 258-59, 262-266.)

Assessing prudence requires that the Commission apply rules and guidelines that have been developed over the past 100 years. As Company witness Steven Fetter testified, "the concept of prudence began in 1923 in a dissent from Justice Brandeis of the US Supreme Court …." (Tr. vol. 26, 93; see *Missouri ex rel. Southwestern Bell Tel. Co. v. Pub. Serv. Comm'n,* 262 U.S. 276, 306-07 (1923) (Brandeis, J, concurring and dissenting). Those rules and standards do not include "culpability." In his testimony, witness Fetter held up as a visual aid one volume of a two-volume reference work ("The Process of Ratemaking;" see Tr. vol. 26, 93)[15] and indicated that the index of the two volumes had "35 subcategories discussing various means of assessing prudence and what it means …[but that he] found nowhere in the two-volume text any mention of culpable or culpability." (Tr. vol. 26, 93.)

In North Carolina, for at least the last 30+ years, the prudence framework has been applied as articulated by this Commission in its Order entered in Docket No. E-2, Sub 537 (the 1988 DEP Rate Case), in which the Commission approved, with some exceptions, costs Duke Energy Progress (DEP) incurred in connection with the construction of Unit 1 of the Shearon Harris nuclear plant. See Order Granting Partial Increase in Rates and Charges, Docket No. E-2, Sub 537 (Aug. 5, 1988) (the "1988 DEP Rate Order"). There, the Commission set out the following principles governing the question of prudence:

First, the standard for judging prudence is "whether management decisions were made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time. … [T]his standard

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Order at 258-59) the prudence framework captures the concept of "reasonable" – costs unreasonably large in size can hardly be said to have been prudently incurred.

[15] https://www.youtube.com/watch?v=PESiQ189BSc at approx. the 5:33 mark

… must be based on a contemporaneous view of the action or decision under question. Perfection is not required. Hindsight analysis – the judging of events based on subsequent developments — is not permitted." 1988 DEP Rate Order at 14.

Second, challenging prudence requires a detailed and fact intensive analysis, and the challenger is required to (1) identify specific and discrete instances of imprudence; (2) demonstrate the existence of prudent alternatives – but a decision cannot be imprudent if it represents the only feasible way of accomplishing a goal; and (3) quantify the effects by calculating imprudently incurred costs. Id. at 15. As to quantification,

- The Commission can only disallow imprudent *expenditures* – that is, actions (even if imprudent) with no economic impact upon customers are of no consequence. As the Commission put it, "There can be imprudent actions without any economic impact. An imprudent decision or action can actually benefit the ratepayer economically. Thus, the identification of imprudence is not in itself sufficient." Id. The Commission rejected the importation of tort or "culpability" concepts into the prudence framework, and kept its focus where it statutorily belongs – upon rate regulation.

- The proper amount chargeable to customers is what the expenditure would have been absent the imprudent acts or decisions of management – in other words, the disallowance must be calculated as the difference between the (presumably) higher cost imprudent action and the (presumably) lower cost prudent action.

The North Carolina Supreme Court found "no error" in the Commission's articulation of the prudence framework in *State ex rel. Utils. Comm'n v. Thornburg*, 325 N.C. 484, 489 (1989), and the framework was most recently followed in the Commission's February 24, 2020 Order in Docket No. E-22, Sub 562 (2020 Dominion Rate Order, or simply, Dominion Order), at 116. A key factor in the prudence framework requires a challenger to identify "specific and discrete instances of imprudence." Necessarily embedded in this factor is an evaluation of the degree to which the utility has or has not acted consistent with industry standards. As two of the leading modern commentators on utility regulation, Lesser & Giacchino, state:

> Electric and natural gas utilities are required to follow a set of basic standards and practices, which together constitute *Good Utility Practice*. FERC defines *Good Utility Practice* for regulated electric utilities as follows:
>
> > Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of *reasonable* judgment in light of the facts known *at the time the decision was made*, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good

> Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Lesser & Giacchino, at 40 (citation omitted) (emphasis in original). Prudence is an attribute of "Good Utility Practice" (id. at 41), and "Good Utility Practice" includes "the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period" (Id. at 40.) That is, Good Utility Practice – prudence – is judged in relation to the utility's conformance with industry standards.

"Used and useful" is a concept directly embedded in the ratemaking statute – N.C. Gen. Stat. § 62-133(b)(1) states that the Commission must "Ascertain the reasonable original cost of the public utility's property *used and useful, or to be used and useful* within a reasonable time after the test period, in providing the service rendered to the public within the State, less that portion of the cost which has been consumed by previous use recovered by depreciation expense …." (Emphasis added). In general, the Supreme Court's treatment of the concept has been in the negative, i.e., asserted as a basis for its decision that something is not "used and useful" – for example, excess common facilities are not "used and useful" as a matter of law, *see Thornburg II*, 325 N.C. at 495-96, and a water treatment plant that was not in service as of the end of the test year and would never again be in service was not "used and useful" within the meaning of N.C. Gen. Stat. § 62-133(b)(1). *State ex rel. Utils. Comm'n v. Carolina Water Serv., Inc.*, 335 N.C. 493, 508 (1994). The reverse, of course, is that if the expenditures do support and provide service to customers, the costs are "used and useful."

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production in the event that they dispute an aspect of the utility's prima facie case. *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions,* 305 N.C. 62, 76 (1982) (*Intervenor Residents*) ("The burden of going forward with evidence of reasonableness and justness arises only when the Commission requires it or affirmative evidence is offered by a party to the proceeding that challenges the reasonableness of expenses…."). If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility, in accordance with N.C.G.S. § 62-134(c). Finally, the Commission's orders must be based on competent, material and substantial evidence in the record of the instant proceeding. N.C.G.S § 62-65(a).

Summary of the Evidence

The Company's Direct Case

Company witness Jessica Bednarcik presented the Company's direct case for recovery of coal ash. Witness Bednarcik testified that she is the Vice President, Coal Combustion Products (CCP) Operations, Maintenance and Governance for Duke Energy. She is a registered Professional Engineer in North and South Carolina and joined Duke

Energy's Environmental Engineering group in 2005. In her current role, witness Bednarcik testified that she manages the team that defines, establishes, and maintains the Company's fleet CCP standards, programs, processes, and best practices for all fossil plant sites. Her team also oversees site operations and maintenance of CCP facilities, including CCR and dam operations and maintenance, production landfills, decommissioning and demolition, and byproducts management. (Tr. vol. 13, 3-4.)

In her testimony, she explained that DEC's compliance actions since January 1, 2018, have been and continue to be reasonable, prudent, and cost-effective approaches to comply with the federal CCR Rule and North Carolina's Coal Ash Management Act (CAMA). (Id. at 193.) Under the CCR Rule and CAMA, DEC is required to close all of its CCR basins in North Carolina and South Carolina. For each activity the Company undertook, witness Bednarcik explained why the costs are necessary to satisfy federal and state regulatory requirements; are appropriate in terms of meeting engineering and environmental standards; and are timely and consistent with the site closure plans. In short, witness Bednarcik's direct testimony established that the actual costs incurred for ash basin closure at each site between January 1, 2018, and June 30, 2019, are reasonable and prudent. (Id. at 193.)

Witness Bednarcik explained that the CCR costs incurred between January 1, 2018 and June 30, 2019 reflect a continuation of ongoing projects that the Company initiated to meet its regulatory requirements. Costs for the initial phases of those projects were the subject of the Company's 2017 Rate Case, in which the Commission concluded that the Company's CCR costs were reasonably and prudently incurred. Witness Bednarcik also explained the closure options available for the Company's low-risk impoundments, including the Company's original plans to close those basins by cap-in-place. With assistance from experienced, professional engineering firms, the Company developed and submitted Closure Options Analysis Reports (COA Reports) to DEQ in fourth quarter of 2018 for the four sites. (Id. at 203.) On April 1, 2019, DEQ ordered Duke Energy to excavate all remaining coal ash impoundments in North Carolina, including the impoundments at Allen, Belews Creek, Cliffside/Rogers, and Marshall. (Id. at 203.) With the exception of preliminary closure plan development, the Company has not begun implementing cap-in-place closure at any of the sites covered by the order. Although some site work has been completed, none is specific to cap-in-place and would have to be conducted in an excavation closure, as well. (Id. at 204.)

Next, witness Bednarcik discussed the unique closure activities that the Company has undertaken at each of its sites, itemizing the associated costs the Company is seeking to recover in the instant case. The ash basins at Allen, Belews Creek, Cliffside/Rogers, and Marshall, all classified as low-risk under CAMA, are under similar closure schedules, and the activities conducted at these sites from January 1, 2018 through January 31, 2020, were relatively the same. (Id. at 204.) During that time-period, the Company developed and submitted the COA Reports and began developing preliminary draft closure plans to execute cap-in-place at these low-risk sites, although no onsite work was performed. (Id. at 204.) Witness Bednarcik explained that the site work for which the Company is currently seeking recovery would have been required in either a cap-in-place or an excavation closure plan. This site activity included pursuing environmental permits, performing groundwater activities, including data review and reporting of groundwater monitoring to comply with the CCR Rule, CAMA, and the Company's NPDES permits. (Id. at 205.) In addition, the Company has begun dewatering the basins at these sites, and incurred costs to plan, design, and install permanent water supplies to neighboring residents to comply with CAMA. (DEC Id. at 205.) Last, witness Bednarcik explained, the Company has incurred several miscellaneous costs, including operating and maintenance costs related to the coal ash landfills and basins. (Id. at 206.)Witness Bednarcik provided a table showing the costs at each basin by category, and denoting the following total costs for which the Company is seeking recovery: Allen ($18,053,874), Belews Creek ($12,474,484), Cliffside/Rogers ($12,694,760), and Marshall ($24,809.902). (Id. at 206.)

Witness Bednarcik testified that Buck was selected as one of three Duke Energy sites for the installation of a beneficiation project pursuant to CAMA. (Tr. vol. 13, 207.) Excavated ash from Buck will be processed through the beneficiation plant and recycled for use in the concrete industry. (Id. at 207.) The Company has begun bulk dewatering of the Buck impoundments and has installed groundwater monitoring wells, which it regularly samples and monitors to comply with the CCR Rule and CAMA. (Id. at 207.) To build the plant, the Company undertook erosion control measures, a sedimentation basin was constructed to capture sediment or soil, and construction began on the foundations and support of the structures. (Id. at 208.) Witness Bednarcik provided a table showing the costs at Buck by category, showing that the Company is seeking recovery of $111,368,167.

Witness Bednarcik next explained that the Company completed excavation of ash from the Dan River impoundments on May 20, 2019. (Id. at 209) Excavated ash from the Dan River impoundments has been transferred to an onsite, CCR landfill. According to witness Bednarcik, DEC excavated 1,426,200 tons of ash from the Primary and Secondary Ash Basins at the Dan River site, (Id. at 209.), and the Company has begun the process of closing the CCR landfill in compliance with state and federal standards. The Company also performed dam decommissioning work on its basins to meet post-closure dam safety requirements. (Id. at 209.) Witness Bednarcik provided a table showing the costs at Dan River by category, showing that the Company is seeking recovery of $63,569,340.

At Riverbend, the Company has completed excavation and removal of CCR materials from the impoundments at Riverbend. (Id. at 210.) From January 1, 2018 through June 30, 2019, the Company excavated a total of 1,479,066 tons of ash from its Riverbend basins, which was then transferred to the Brickhaven Structural Fill site in Chatham County, NC. (Id. at 210.) Decommissioning and site grading work has also begun at Dan River to meet post closure dam safety standards, and the Company regularly monitors groundwater at the site. (Id. at 211.) Witness Bednarcik provided a table identifying the costs at Riverbend by category and showing that the Company is seeking recovery of $103,145,059.

In addition to closure costs, witness Bednarcik explained that the Company is seeking to recover the cost of paying a fulfillment fee to Charah, LLC (Charah). In 2014, Duke Energy entered into a contract with Charah to dispose of coal ash from the Riverbend site, as well as DEP's Sutton, Cape Fear, H.F. Lee, and Weatherspoon sites. (Id. at 212.) After CAMA was amended to include beneficiation requirements, however, Duke Energy was unable to transfer the contracted-for amount of ash to Brickhaven and did not send any ash, whatsoever, to the Sanford Colon mine. (Id. at 212.) **[BEGIN CONFIDENTIAL]** [redacted] [**END CONFIDENTIAL]** Witness Bednarcik argued that engaging Charah was the best option for customers compared to the other options that Duke Energy had available at the time to meet regulatory requirements. (Id. at 213.)

Witness Bednarcik next explained the closure activities and costs at W.S. Lee. There, the Company has engaged in site preparation and excavation of the Secondary Ash Basin, as well as dewatering and decanting, and groundwater monitoring. (Id. at 213-14.) Witness Bednarcik provided a table identifying the costs at W.S. Lee by category and denoting the Company is seeking recovery of $13,511,999.

Finally, witness Bednarcik explained that the Company has taken sufficient measures to ensure that costs for the closure projects are appropriately managed and minimized, and that all costs for which the Company is seeking recovery were reasonably and prudently incurred. (Id. at 217.)

Summary of Intervenors' Evidence

Public Staff

1. Prudence-Based Disallowances – Garrett and Moore

Witnesses Bernard L. Garrett and Vance F. Moore proposed a number of prudence-based disallowances with respect to the Company's CCR costs. Witnesses Garrett and Moore are principals in and founding members of Garrett & Moore, Inc., which provides environmental engineering and consulting services to power and waste industries. (Tr. vol. 20, 192.) After reviewing the Company's direct case, they proposed three distinct disallowances: (1) witness Garrett proposed a disallowance of $46,142,699 which represents DEC's allocation of the fulfillment fee the Company paid to Charah related to the disposal of ash from the Riverbend plant at the Brickhaven structural fill site (Id. at 204.); (2) witness Garrett proposed a disallowance of $29,250,905 related to certain costs incurred for excavation at the Dan River plant. (Id. at 204.); and (3) witness Moore proposed a disallowance of $6,809,160 in costs to construct the beneficiation unit at the Buck site. (Id. at 173.) Aside from these three cost categories, witness Moore testified that he found the Company's requested recovery for CCR costs incurred at the Allen, Belews Creek, Cliffside, and Marshall plants to be reasonably and prudently incurred. (Id. at 175.)

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**

Next, witness Garrett testified that the Commission should disallow $29,250,905 of costs incurred related to basin closure at the Dan River plant. (Id. at 247.) In support of his recommended disallowance, he argued that DEC incurred additional, unreasonable costs related to how the Company contracted for basin closure because the Company: (1) failed to negotiate a performance bond into its contract with Parsons Environment & Infrastructure Group Inc. (Parsons); (2) failed to require security when it became apparent Parsons was falling behind the schedule set for ash excavation; (3) failed to impose back-charges on Parsons for work completed by Trans Ash; (4) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** (6) authorized extended working hours and supplemental ash conditioning that incurred unnecessary cost; and (7) paid a premium to excavate ash before the CAMA closure deadline for ash that was not subject to CAMA. (Id. pp. 247-48.) Witness Garrett testified that he believed each of these itemized cost increases could have been avoided if the Company had sought an extension to the CAMA closure deadline as DEP did at the Sutton plant. (Id.)

Finally, witness Moore testified that the Commission should disallow $67,809,160 in CCR costs incurred to construct the Buck beneficiation unit. (Id. at 173.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** In particular, witness Moore testified that the Company should have taken a number of steps to mitigate the high cost, including: (1)

soliciting bids from a broader group of companies; (2) entering into three separate contracts for the construction of one STAR facility each, which he alleges would have been cheaper; (3) seeking statutory relief from the CAMA amendment's beneficiation requirements from the General Assembly; and (4) seeking guidance from the regulator, DEQ, as to whether some waiver or compromise would be possible, and what the consequences would be if it did not comply with the beneficiation requirements of the CAMA Amendment. (Id. at 188-89.)

2. Discrete Culpability-Based Disallowances – Junis

Public Staff witness Junis is an engineer with the Water, Sewer, and Telephone Division of the Public Staff. (Id. at 401.) He testified that the Commission should impose two broad categories of disallowances: (1) expenditures of $298,433 related to groundwater extraction and treatment at the Belews Creek plant; and (2) costs incurred to connect eligible residential properties to permanent alternative water supplies ($16,882,665) and/or install and maintain water treatment systems ($962,524).

With respect to permanent alternative water supplies, witness Junis acknowledged that the Commission allowed recovery of these expenses in the 2018 Order, but asked the Commission to take a "fresh look" at these costs in light of what he interpreted as numerous "violations" of groundwater standards since the Company's last case. (Id. at 458.) He testified that, in his view, the evidence showed a total of 3,972 instances of new groundwater violations surrounding the Company CCR impoundments and that the Company had not challenged any of the measured exceedances. Witness Junis argued that there would have been no need for the Company to extract and treat groundwater had it not been responsible for contaminating the groundwater in the first place. (Id. at 459.) In support of this position, witness Junis stated that legal counsel informed him that neither CAMA nor the CCR Rule would have required extraction and treatment of groundwater if there were no violations of groundwater quality standards. (Id.)

Regarding permanent alternative water supplies and installation and maintenance of water treatment systems, witness Junis acknowledged that the costs were incurred pursuant to a CAMA requirement, N.C. Gen. Stat. § 130A-309.22(c1), but argued that the Company should be responsible for the costs because it created the contamination risk that, in his view, the legislature was forced to address. (Id. at 461.) He further testified that the Commission previously disallowed the costs to provide bottled water that was similarly mandated by CAMA, and there is no meaningful difference between the two mandates with respect to recovery. (Id.)

3. Culpability-Based Disallowance – Equitable Sharing

In addition to the prudence-based disallowance, witness Junis also advocated for the Commission to implement an "equitable sharing" that would allow the Company to recover just 50% of its otherwise recoverable CCR costs. Using this methodology, customers would be responsible for 50% of the recoverable CCR costs, and shareholders would bear the burden of the remaining costs. (Id. at 462.)

In support of his recommendation, witness Junis testified that the Company has accumulated a record of significant environmental violations caused by leaking coal ash basins, which have, in his view, resulted in unlawful releases of regulated contaminants to groundwater and surface water. Because, according to witness Junis, DEC is "culpable" for these purported environmental violations, he argued that it would be manifestly unjust to require ratepayers to bear all the deferred coal ash costs where those costs include corrective actions to remedy the Company's environmental violations. (Id. at 463-64.)

Witness Junis went on to testify that given the difficulty in identifying the costs of corrective action for environmental violations that DEC would have incurred in the absence of CAMA and the CCR Rule, as well as the difficulty of determining whether North Carolina would have required closure of ash basins in the absence of the Dan River spill, he does not believe the traditional imprudence approach is feasible for most of DEC coal ash costs. He contended that equitable sharing is therefore appropriate because the costs of remediation and closure of the Company's coal ash disposal sites are intertwined with the Company's failure to prevent groundwater contamination as required by the 2L rules. He concluded that this case presents factual circumstances (extensive environmental violations) where the determination of "reasonable and just rates" under N.C. Gen. Stat. § 62-133(d) requires a qualitative judgment of the Commission for a 50%—50% sharing of coal ash disposal site closure and remediation costs. (Id. at 467.)

Public Staff witnesses Lucas and Maness also jointly provided testimony to respond to a portion of the Commission's *Order Directing the Public Staff to File Testimony,* dated January 22, 2020. The Order required the Public Staff to file testimony on several topics, including: (1) whether DEC included coal ash impoundment closure costs in net salvage for decommissioning DEC's coal plants; and (2) estimated costs for CCR remediation as initially proposed and after the December 31, 2019, Settlement Agreement (Settlement Agreement) between DEC and DEQ.

Witnesses Lucas and Maness testified that a review of DEC's depreciation studies stretching back to 2003 does not indicate specifically whether the costs of decommissioning its coal ash impoundments were included in its net salvage percentages used to help determine depreciation rates. However, the testified that DEC states in its response to Public Staff discovery that the percentages used in the studies do not "include or account for anticipated costs of coal ash removal or remediation, or retirement/decommissioning of coal ash impoundments or storage facilities." Therefore, they testified without more detailed information, they did not find it possible to conclude, with absolute certainty, that no portion of the previously utilized salvage percentages are allocable to impoundment retirement or closure costs, and therefore recommended the Company address this issue in its rebuttal testimony. Through Confidential Lucas and Maness Table 1, the witnesses provided a summary of DEC's projected CCR remediation costs for 2015 through 2079 at various points in time in response to request (2) of the Commission's Order Directing the Public Staff to File Testimony, which totaled to $5,012,867.32.

Other Intervenors' Disallowance Theories

The AG through witness Steven Hart, Sierra Club through witness Mark Quarles, and CUCA through witness Kevin O'Donnell submitted testimony supporting disallowances of DEC's CCR costs. None of these witnesses applied the prudency standard to support their recommended disallowances. Instead, the AG, Sierra Club, and CUCA based their disallowance recommendations on methodologies or theories that have never been applied or accepted by the Commission. Unable to identify discrete, imprudently incurred costs, intervenors therefore ask the Commission to disallow DEC's prudently incurred CCR costs.

AG Witness Hart recommended a range of disallowances, between approximately 10 percent and approximately 50 percent, on the grounds that the Company had not adequately addressed CCR storage and closure of its ash basins before 2014. While witness Hart is a Licensed or Professional Geologist in a number of states including North Carolina and South Carolina (Tr. vol. 16, 699-701), he testified that he is not an engineer, has never designed an ash basin, and has never managed or operated an ash basin. (Id. at 854.) He opined that the utility industry, including DEC, knew about the potential for contamination of groundwater from coal ash basins as early as the 1980s. (Id. at 705.) He then testified that by the early 2000s, as a result of EPA's Regulatory Determination in 2000 concerning the management of CCRs, that DEC should have known that it would face increased scrutiny, environmental sampling requirements, and potential mandates to close its ash basins. (Id. at 705.) After DEC began groundwater monitoring at all of its sites in 2008 through its voluntary participation in the Utility Solid Waste Activities Group (USWAG) Action Plan, witness Hart also opined that DEC was not proactive with regard to groundwater contamination at its coal ash basins, and instead chose to wait until regulatory agencies noted groundwater contamination concerns from DEC's data submittals in the 2009 to 2010 timeframe. (Id. at 706-8.) Witness Hart testified that while the CCR Rule and CAMA brought greater regulatory certainty about the management and closure of coal ash ponds, DEC should have taken steps to manage CCR differently under North Carolinas groundwater program (2L Rules). (Id. at 718-19.) However, at no point during his investigation did witness Hart attempt to meet with or interview anyone from DEQ to determine whether DEQ concurred with his opinion that DEC was not proactive enough. (Id. at 884-86.)

Witness Hart opined that DEC should have taken responsive action sooner and initiated a systematic plan to address its coal ash basins by converting facilities to dry ash handling, eliminating other wastewater streams, closure planning, and evaluating methods to reduce environmental impact while the basins were still operational. (Id. at 821.) He opined that DEC's costs would be lower had it taken earlier action, but he admitted that any analysis of specific costs the DEC would have incurred had it responded earlier to the presence of groundwater impacts at its CCR basins is difficult. He explained that the difficulty arises from the fact that he could not retroactively determine what costs would have been incurred 10 or more years ago and because some of the costs would have resulted in additional costs that would have to be accounted for to determine whether there was a net increase/decrease in costs for customers. As an example, witness Hart explained that the conversion to dry ash handling would have led to increased costs to transport ash to an off-site or on-site landfill. Therefore, witness Hart was not able to provide line-by-line estimates of what the Company's earlier costs would have been. Instead, witness Hart concocted a methodology that assumed the activities for which DEC is requesting cost recovery at this time would have been similar to the activities that would have been conducted at an earlier time. Then he de-escalated the cost by considering the inflation rate between the time when DEC knew it had issues with groundwater contamination and when it started planning for basin closure in 2014. Based on his calculations, he recommended a disallowance range of $50 million if DEC had started closure planning in 2010 to $190 million if DEC had started planning in 1989. (Id. at 825-29.)

Sierra Club witness Quarles provided no disallowance recommendation, but merely opined that the Company's CCR costs would have been lower had it converted to dry ash handling at some point in the past. (Id. at 52-59.) Similar to his testimony in the Company's prior rate case, witness Quarles' testimony in this case asserted that it was unreasonable for the Company to continue operating unlined coal ash basins after the 1980s. He testified that the Company should have closed and remediated unlined impoundments and should have converted to dry ash handling in lined landfills. (Id. at 58-9; *compare* Tr. vol. 6, 112 (Docket No. E-7, Sub 1146).)

CUCA witness O'Donnell testified that DEC should not be allowed to recover coal ash expenses associated with any plant that is not subjected to CCR but is subjected to CAMA. (Tr. vol. 20, 70.) He further clarified that to the extent that any site is no longer receiving coal ash, the plant's remediation costs should be not be borne by the Company's customers in this case or any future cases. (Id.) Witness O'Donnell did not advocate for a specific monetary value that should be disallowed from the Company's cost recovery. He simply testified that he does not believe that consumers should pay all of the Company's costs to clean up coal ash at its sites. (Id.)

The Company's Rebuttal Case

Rebuttal Testimony of James Wells

DEC offered the rebuttal testimony of James Wells, Vice President – Environmental Health and Safety Programs and Environmental Sciences for DEC, to respond to the testimony of Public Staff witness Junis, AG witness Hart, and Sierra Club witness Quarles regarding the Company's historical environmental compliance record and CCR management practices. (Tr. vol. 27, 19-20.) Witness Wells testified that he earned a B.S. in Technology from Regents College at the University of the State of New York, an M.S. in Nuclear Engineering from the University of Cincinnati, and a J.D. from the Salmon P. Chase College of Law at Northern Kentucky University. He testified that he joined Duke Energy in 2009 as an Environmental Health and Safety attorney after serving in a similar role at General Electric Company. He testified that he transferred from the legal department to EHS in 2015 as Vice President, EHS Coal Combustion Products, then to his current role in 2018. (Id.)

Witness Wells explained that no intervenor witness could identify discrete, imprudent costs that the Company is incurring today as a result of any alleged historical mismanagement of CCR; therefore, intervenors are seeking to disallow *prudently-incurred* costs. He noted that intervenors have recycled theories that they put forward in DEC's 2017 Rate Case, and that those arguments were rejected by the Commission. For example, he noted that Public Staff has again recommended an "equitable sharing" disallowance. He also testified that no intervenor has conducted a prudence analysis. (Id. at 21-2; 25-27.)

Witness Wells responded to intervenors' allegations that DEC failed adequately manage the risks of operating unlined surface impoundments to store or dispose of CCR. He testified that the Company's construction and continued use of unlined surface impoundments, or ash basins, to store and dispose CCR was reasonable, prudent, and consistent with industry standards and applicable regulatory standards. All but one of the Company's CCR basins were constructed before 1982. He also testified that the Commission, from about 1967 through about 2009, had the sole authority to regulate utility dams, including the dams that formed DEC'S CCR impoundments. He explained that under the Commission's purview, the Company was required to perform dam safety inspections every five years, and that an important aspect of those inspections was identifying, characterizing, and monitoring seeps that may be emanating from the ash basins. He explained that those inspection reports, which were performed by independent engineering consultants, were provided to DEQ for review and were filed with the Commission in Docket Nos. E-100, Sub 23 and E-100, Sub 23A. (Id. at 28-30.)

Witness Wells testified that the Company's ash basins are not lined, but that the widely accepted understanding was that most impacts, if they materialized, were insignificant. He testified that studies performed in the late 1970s and throughout the 1980s that were applicable to DEC's ash basins consistently demonstrated that harm to groundwater quality from its unlined impoundments was nonexistent or insignificant. (Id. at 30-31.) He testified that even today, groundwater and surface water monitoring has demonstrated that DEC's ash basins have not caused significant harm to the environment or public health.

Witness Wells' testimony demonstrated that the Company was proactive in the areas of environmental compliance and stewardship, and he opposed intervenors' implication that DEC failed to adequately monitor groundwater or otherwise evaluate potential risks posed by its unlined ash basins. He explained that DEC did not ignore the risk of groundwater contamination; instead the Company took proactive actions to assist regulators and the industry to improve and develop the scientific knowledge on the subject. These efforts went beyond what was required by environmental regulators – which was no required monitoring – and exceeded industry standards. (Id. at 288-89.) He testified that in 1978, a year before North Carolina promulgated groundwater regulations, DEC voluntarily partnered with EPA to study groundwater quality at the Allen Plant. He explained that the purpose of the monitoring program was not solely to characterize site conditions at Allen, but also "to evaluate the performance of Duke's ash basins, and their effect on groundwater movement and water quality" across its system.

He explained that Allen was selected in particular, “as being representative of the Piedmont region and the combined ponding of fly and bottom ash. The site was also selected to investigate Duke Power’s practice of treating boiler cleaning waste in the ash basin.” He testified that around the same time, the Company also began to conduct leachate tests on ash from all of the sites to determine the concentrations of constituents with the potential to migrate to groundwater. He testified that the Company engaged in this effort because recognized that data that had been collected and studied by EPA, to date, was not necessarily applicable to the Company’s service area; so, the Company collected additional data from its sites for the express purpose of aiding regulators in developing future groundwater standards that could be used at the regional or state level. (Id. at 37-38.)

Witness Wells testified that the EPA-sponsored and internal Company studies at Allen demonstrated that wet disposal of coal ash had no significant impact on groundwater at DEC sites, all of which are located in Piedmont soils. Another EPA-sponsored study at Allen in 1985, for example, indicated that arsenic, a constituent of particular concern to EPA at the time, would not be expected to exceed drinking water standards for another 100 years or longer due to the attenuative capacity of Piedmont soils. (Id. at 226.) Adding to that body of knowledge, witness Wells testified that DEC conducted an investigation in 1987 at the Riverbend Plant, which was headed by the “father of Duke hydrogeology,” which provided additional support for the conclusion that groundwater impacts from the Company’s ash basins were considered minimal. (Id. at 233.) He testified that, while the Company may have been aware in the 1980s that unlined impoundments could potentially impact groundwater, there was no substantial evidence showing that there was significant impacts resulting from *DEC’s facilities*. He testified that this conclusion was supported by EPA’s 1988 Report to Congress, which stated “that current waste management practices [including unlined ash basins] appear to be adequate for protection of human health and the environment.” Witness Wells rejected Public Staff’s insinuation during cross-examination that continued monitoring at Allen would have been prudent following the various site studies. He testified that the data to that point repeatedly showed that groundwater was flowing away from receptors and that there was no migration of constituents beyond the basin. He, therefore, concluded that no further groundwater monitoring would have been necessary or prudent at that time. (Id. at 243-44.)

Witness Wells testified that following the 1988 EPA Report, the Company began monitoring groundwater around unlined ash landfills at Belews Creek and Marshall, as required by DEQ, in 1989. Although the monitoring did indicate some exceedances of groundwater standards, witness Wells explained that the exceedances were primarily for standards associated with naturally occurring conditions—iron, manganese, and pH. He explained that the data did not reflect a pattern of ash constituents migrating out from the landfills. He then testified that in 1993, groundwater monitoring requirements were added to the NPDES permits for Dan River and W.S. Lee Steam Stations. He explained that groundwater monitoring at Dan River indicated exceedances for pH, iron, and manganese, all of which can occur naturally in the soils and groundwater at Dan River, and which were seen in the site’s background well. He explained that to the extent monitoring indicated exceedances of standards at W.S. Lee, it was for South Carolina secondary maximum contaminant levels, which are regulated for aesthetics such as taste and odor and not health concerns (e.g., pH, iron, total dissolved solids, and manganese). Witness Wells explained that based on these data sets, there was no indication that the basins were likely to materially impact groundwater or present a risk to public health or the environment. (Id. at 38-40.) He testified that these studies supported DEC determinations as to what, if any, additional groundwater monitoring was needed going forward. (Id. at 236.)

He testified further that even modern data collected under CAMA and the CCR Rule largely corroborate the conclusions reached by scientists decades ago. He explained that current data demonstrates that the contaminant plume from ash basins is stable and not likely to grow for hundreds of years due to the attenuation capacity of the soils, even if the Company were to take no action. (Id. at 233-34.) When asked on cross-examination whether earlier closure would have reduced the number of coal ash constituents in the groundwater, witness Wells testified that that is not necessarily the case when the groundwater plume is stable and not moving, which is what the models show for DEC's facilities. One would still have had to address the same subsurface area, even if the facility was closed decades earlier. (Tr. vol. 28, 71-72.)

He then testified that in the mid-2000s, the Company once again voluntarily monitored groundwater quality through the Company's participation in the USWAG Action Plan. He explained that initial sampling at Allen reflected exceedances of only the standards for pH, iron, and manganese, which were naturally occurring parameters in North Carolina. He testified that initial sampling at Buck and Marshall in 2007 and at Riverbend in 2010 reflected exceedances of naturally occurring parameters, plus boron. He explained that around 2009, DEQ began gradually adding groundwater requirements to NPDES permits as they were reissued or modified. As additional data became available and both the Company's and DEQ's understanding of groundwater impacts matured, he testified that DEQ issued a policy memo, dated June 17, 2011, titled "The Policy for Compliance Evaluation of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirements" (2011 DEQ Policy). He described the 2011 DEQ Policy, which included a detailed flow chart dictating the steps to be taken by DEQ and regulated facilities upon the identification of a groundwater exceedance near a coal ash pond. Those steps included, but were not limited to: (1) verifying the accuracy and significance of the results of the groundwater testing; (2) determining whether and to what extent the identified substance could be naturally occurring; and (3) evaluating other possible sources of the identified substance. He explained that a*fter* these steps were completed, and it was determined that a particular exceedance may have been caused by migration of water from coal ash ponds, the 2011 DEQ Policy dictated that the parties work together to develop a corrective action plan in accordance with North Carolina's groundwater rules. He testified that DEC continued cooperating with DEQ under this policy until it was eventually superseded by CAMA's groundwater assessment and corrective action procedures. (Id. at 38-40.)

Witness Wells rejected Public Staff witness Junis' contention that DEC should have implemented comprehensive groundwater monitoring at all of its sites at some unspecified point in time before the Company's participation in the USWAG Action Plan in the mid-2000s. He testified that the evaluations at DEC's sites and the industry-wide evaluations did not support the need to conduct groundwater monitoring at all locations. Moreover, witness Wells testified that DEQ never required such groundwater monitoring. He explained that DEQ gradually added groundwater monitoring to the Company's NPDES permits over a span of two decades, beginning in 1993 at Dan River. He testified that groundwater sampling data that was collected was always submitted to DEQ, and DEQ possessed the expertise to evaluate that data and the authority to require additional monitoring or other corrective action, if deemed necessary. He asserted that had DEQ determined that DEC's should have begun groundwater monitoring at all of its sites earlier, DEQ certainly had the regulatory authority to include groundwater monitoring as a condition in all of DEC's NPDES permits at any time after 1984. Yet, he explained that it was not until 2013 that DEQ included groundwater monitoring as a requirement in all of the Company's NPDES permits. No intervenor could explain exactly how and where the Company should have implemented groundwater monitoring differently, or how the costs the Company has incurred under CAMA and the CCR Rule would be lower if the Company had monitored groundwater differently or more aggressively. (Id. at 41-46.) Witness Wells also noted that the only reason that intervenors were even able to cherry-pick data points from historical monitoring data was because the Company voluntarily engaged in groundwater monitoring, unlike a majority of its industry peers. (Id. at 234-35.)

Witness Wells testimony next responded to intervenors' criticisms that DEC failed to take appropriate action once it had knowledge of the potential environmental risks of operating unlined ash basins. He noted that Public Staff witness Junis asserted that the Company "failed to modernize its practices despite the available knowledge," but that witness Junis did not articulate the specific actions the Company should have taken, other than vague "comprehensive" groundwater monitoring, where the Company should have taken those actions, or when the Company should have acted. Witness Wells testified that AG witness Hart asserted that the Company could have taken earlier actions to minimize groundwater contamination, including converting to dry fly ash and bottom ash handling, removing ash from the basin on a frequent basis, eliminating wastewater streams and hydraulic loading from non-coal ash sources, removing the ash and installing a bottom liner, lowering the water level and/or dewatering the pond to decrease hydraulic loading, and ultimately pond closure. Witness Wells noted, that like Public Staff witness Junis, AG witness Hart failed to state where or when the Company should have taken any or some of these actions, nor did he account for the historical costs of those actions. Witness Wells also responded to Sierra Club witness Quarles assertion that the Company should have transitioned from wet ash handling to dry ash handling much sooner; however, Witness Wells noted that witness Quarles, like intervenor witnesses Junis and Hart, failed to identify with any specificity what specific actions the Company should have taken, where or when the actions should have been taken, nor did he account for the costs of those actions. On cross-examination, witness Wells also explained that witness Quarles underlying assumption—that earlier conversion to dry ash would mean fewer tons of ash in basins—was flawed. He testified that CCR was sluiced to the basins, but was then often dredged or moved out of the basin. (Tr. vol. 28, 76.)

Witness Wells explained that the one-size-fits-all approach to CCR management advocated by intervenors was never the industry or regulatory standard in North Carolina or South Carolina. He asserted that in the absence of any environmental or regulatory justification at a particular site and given the information before the Company over the time period in question, overhauling its operations at all of its sites would not have been economically justified or reasonable. (Id. at 46-50.)

With regard to the suggestion that the Company should have converted all sites to dry ash handling at some prior point in time, witness Wells responded that given the lack of a regulation requiring dry ash handling or evidence indicating actual, significant impacts from ash basins, there was no point prior to the passage of the CCR Rule or CAMA when it would have made sense for DEC to take on the significant expense of switching to dry fly ash or dry bottom ash handling at all facilities. With that said, witness Wells noted that the Company *did* convert to dry fly ash handling at Belews Creek when scientific evidence and data supported making the operational change to address surface water quality in Belews Lake. After the EPA's regulatory determination in 2000, which identified the potential need for additional regulation of CCR management practices under RCRA Subtitle D, witness Wells testified that the Company and industry implemented the USWAG Action Plan to inform future regulatory decisions or demonstrate a potential non-regulatory approach to address EPA's concerns. (Id. at 50-52.)

Regarding AG witness Hart's assertion that the Company should have ceased treating other wastewaters from plant operations in CCR basins, witness Wells noted that DEC practices were fully consistent and compliant with DEQ- and DHEC-issued NPDES permits and industry standards. He explained that under the effluent limitations guidelines that were in place before 2015, surface impoundments were classified as "Best Available Technology" for other utility plant wastestreams. He noted that under the EPA's 2013 proposed rule amending the effluent limitation guidelines for the utility industry, handling of these waste streams was the common practice in the industry. Witness Wells also asserted that AG witness Hart failed to consider that several wastestreams were introduced to the Company's ash basins as a direct result of compliance with other environmental regulations, including air regulations that required the implementation of new air pollution control devices. Witness Wells testified that witness Hart did not suggest an alternative to complying with emissions standards, nor did witness Hart suggest how the additional waste streams resulting from the control devices should have been handled differently. Lastly, witness Wells testified that AG witness Hart failed to demonstrate how groundwater conditions would be different at any site or how the Company's closure strategy under federal or state law would be any different had the Company not introduced those waste streams to the ash basins, despite being authorized by permit to do so. (Id. at 52-53.)

Regarding intervenors criticism that DEC should have closed its unlined ash basins earlier, witness Wells testified that intervenors ignore, and therefore substitute their judgement for, DEC's environmental regulators. He testified that DEC's environmental regulators, equipped with the same data and studies as the Company, did not see a sufficient environmental justification for requiring the Company to cease operating its unlined basins. As witness Wells testified, environmental regulators continued to issue permits authorizing the Company to operate its unlined basins through the 2000s and early 2010s. (Id. at 54-55.)

Witness Wells next rejected witness Junis' assertion that evidence of exceedances of groundwater standards is evidence that DEC mismanaged its ash basins. Witness Wells stated that the existence and number of groundwater exceedances at or beyond the compliance boundaries at DEC sites is rather a function of where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way unlined basins are viewed. He explained that under the 2L Rules and the 2011 DEQ Policy implementing those rules, an owner/operator was required to report an exceedance and work with DEQ to determine whether it was due to permitted activity, assess the extent of the exceedance, and undertake corrective action. He testified that the existence of past and present groundwater exceedances reflects historical construction practices and the evolution of groundwater assessment and corrective action under modern laws. He explained that an exceedance is a data point that informs whether and to what extent further study is required to assess potential risk. He asserted that this is a complex and highly technical task that takes into account many different factors and simply triggers additional investigation and potential corrective action. He testified that the Company has worked with DEQ and complied with this process. He noted that the Commission agreed with his view of the Company's compliance record in 2017 Rate Case Order when it found that "compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery." 2017 Rate Case Order at 299. (Id. at 56-57.)

Witness Wells likewise rejected Public Staff witness Junis' assertion that DEC has been responsible for significant new violations of groundwater standards since the Company's 2017 Rate Case. Witness Wells explained that the increase in sample results that witness Junis deems "violations" is the result of the fact that intensive monitoring at the sites has continued since 2017. He testified that, on some cases, new wells have been installed since 2017. He also noted that the location of compliance boundaries has changed, so that some wells were reclassified as being located "at or beyond a compliance boundary." He explained that the purpose of the ongoing monitoring is to help the Company and its regulators better understand site specific conditions to develop appropriate corrective actions, and that the additional wells and sampling have achieved that purpose. He explained that, for example, DEC retained the consulting firm Arcadis to perform trend analysis on the wells at these sites. He testified that the trend analysis used several different methods to determine whether concentrations of constituents in individual wells are increasing, decreasing, or stable. He testified that based on this evidence, the characteristics of groundwater contamination around the ash basin remains similar to what the Company was seeing in 2017. Witness Wells asserted merely counting the number of exceedances, as witness Junis did, does not provide an accurate picture of groundwater conditions at any given cite. Using Allen as an example, witness Wells explained that in 2017, DEC provided the Public Staff with data for 173 sampling events from 18 monitoring wells. In contrast, he testified that 2019 data that was provided to the Public Staff reflects 1,491 sampling events from 248 wells—an increase of 230 wells. He explained that new wells were often added in areas already known or suspected to be within a groundwater plume, which is standard practice and was done intentionally to more precisely delineate the plume boundary. He testified that both old and new wells were sampled repeatedly from 2017 through 2019; in some cases, the same wells were sampled twice in one day. He explained that when the same well is resampled during the same day or even months later, and both results are above the groundwater standard, it does not mean that conditions have worsened. He explained that, likewise, a site that samples the same well two times a year is not two times worse than if it sampled that well just once a year. Rather than indicating mismanagement, witness Wells asserted that DEC's groundwater assessment efforts over the past two years demonstrates responsible actions that enable the Company and its regulators to better understand the impacted areas and drive appropriate corrective action. Witness Wells noted that witness Junis' position leaves the Company in an untenable position. He testified that witness Junis seeks to punish the Company for prudently meeting its CCR Rule and CAMA obligations to collect groundwater samples to characterize groundwater impacts. He also notes that if the Company had not complied with the CCR Rule and CAMA by reducing the number of wells drilled or samples collected to avoid witness Junis' criticism, the Company would be vulnerable to legal challenges for violating those regulations. (Id. at 63-65.)

Regarding Public Staff witness Junis' testimony regarding seeps, witness Wells asserted that the existence of seeps at ash basins is not evidence that the ash basins were mismanaged. Witness Wells testified that all earthen dams, including those that form surface impoundments for storing ash, are prone to the movement of liquid through porous features within those structures through a process known as "seepage." He explained that such seepage is common, expected, and, to a degree, necessary to maintain the stability of an earthen dam or dike wall. Absent a certain amount of seepage, he explained that earthen dams can become over-saturated, which may reduce the margins of safety and weaken structural integrity. He testified that certain of DEC'S CCR impoundments feature engineered toe drains within the dam structures to collect seepage. (Id. at 58-9; 295-306.)

Witness Wells further explained that addressing seeps at the Company's ash basins has been an iterative process that has required significant coordination and clarification from the Company's environmental regulators. He testified that EPA first directed permitting authorities to address seeps in 2010, and at that time, the Company approached DEQ to determine the appropriate approach to address seeps and began including them in permit applications. He noted that DEQ did not consider seeps to have a significant environmental impact. He also noted that EPA and DEQ did not appear to agree on the appropriate approach to address seeps. Accordingly, Witness Wells explained, DEC entered into a special order by consent (SOC) with DEQ to address seeps at its coal plants. He explained that the SOC provides regulatory clarity and certainty as to the appropriate monitoring frequency, parameters to be sampled and limits with respect to the non-engineered seeps, while requiring the Company to accelerate the schedule for decanting water from the basins, a process which is expected to substantially reduce or eliminate seeps. (Id. at 60-62; 66-67.)

Witness Wells asserted that DEC basin closure and groundwater assessment/corrective action processes demonstrated why premature closure or retrofitting of basins would have been unreasonable without sufficient regulatory guidelines or impetus. He explained that ash basins are large, permitted wastewater treatment units, and DEC operated its ash basins consistent with its permits for decades. He testified that the ash basins served power plants, which had very little leeway for downtime while they are generating electricity for DEC's customers. He explained that efforts to transition to new ash handling equipment and treatment units had to be carefully planned and executed, including necessary changes to NPDES permits to accommodate developing construction schedules. He testified that assessment of groundwater in conjunction with closure requires installation of a large number of wells, as well as an understanding of groundwater flow and contaminant fate and transport over a large area. He testified that after the passage of CAMA and even with decades of earlier data, it took DEC and DEQ over five years of sustained effort to decide what kinds of information were necessary to support decision-making, and to collect the information and present it in the form of corrective action plans. He asserted that DEC has been successful in this effort because it had a clear mandate in the CCR Rule and CAMA, dedicated and skilled employees, and financeable and regulatory stability. (Id. at 68-69.)

Rebuttal Testimony of Marcia Williams

In addition to witness Wells, DEC also provided the expert witness testimony of Marcia Williams to respond to intervenors' testimony regarding CCR costs. Witness Williams testified that she has had an almost 50-year career centered on environmental protection and regulation, including government service with the EPA (over 17 years), senior management in the waste management industry (approximately 3 years), and consulting for private industry and public agencies (almost 30 years). She testified that her career has focused on compliance with the Resource Conservation and Recovery Act (RCRA), the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), the Clean Water Act (CWA), and the Toxic Substances Control Act (TSCA). (Tr. vol. 27, 77-84.)

Witness Williams testified that from 1985 to 1988, she served as Director of the Office of Solid Waste (OSW). She testified that during her tenure as Director, OSW worked on completing the various reports to Congress on "special wastes" required by amendments to RCRA that were enacted in 1980, including the Bevill Amendment. She explained that the Bevill Amendment exempted fossil fuel combustion waste from the "hazardous waste" category pending further study by EPA, and required EPA to submit a formal report to Congress regarding its findings. She testified that the 1988 Report to Congress entitled *Wastes from the Combustion of Coal by Electric Utility Power Plants*, which cited throughout the record, was finalized and published by EPA at the end of her tenure as OSW Director. She also testified that during her tenure as Direct, EPA was also completing a multi-year effort to characterize the almost 200,000 non-hazardous waste surface impoundments and over 15,000 landfills in the U.S. from the perspective of environmental design and operational controls. She testified that he 1988 Report on Solid Waste Disposal in the United States, which summarized the work performed by the Agency over the previous four years, was issued shortly after she left EPA. (Id. at 80-81.)

Witness Williams provided an overview of the federal government's study and regulation of coal combustion residuals (CCR). Witness Williams reached the following four conclusions in her testimony: (1) under the federal regulatory process governed by the Administrative Procedure Act (APA), it is difficult to predict the exact nature of future regulatory requirements until a final rule has been issued; (2) in North Carolina, owners and operators of coal ash basins faced significant uncertainty regarding the regulatory requirements for managing CCR until the passage of CAMA and the promulgation of EPA's final CCR Rule, and that site-specific clarity for the Company was not achievable until February 5, 2020, when the settlement between the Company and DEQ was approved; (3) in light of these uncertainties, owners and operators of coal ash ponds were acting prudently by waiting until after CAMA and the CCR Rule became law to take specific actions to upgrade or close ash ponds as long as they were working cooperatively with environmental officials to address any site-specific environmental issues; and, (4) prior to the enactment of CAMA and promulgation of the final CCR Rule, an accurate estimate of the costs associated with ash pond closure (even assuming that closure would have been required) would have been extremely difficult with a high likelihood for significant over- or under estimation, and that even with those regulations, fully known and measurable estimates required completion of recently-finalized site-specific closure agreements. (Id. at 104-05.)

Witness Williams testified that evidence existed exemplifying that the Company had evaluated whether the continued operation of its unlined ash ponds was protective of groundwater, stating that DEC began studying the composition of its coal ash leachate in the late 1970s and early 1980s. She referenced several studies the Company performed, and testified that these were precisely the types of groundwater and surface water evaluations that EPA recognized as one appropriate way to demonstrate compliance with the EPA solid waste criteria, issued in 1979. Further, in light of these types of Duke Energy studies, along with the results presented in EPA's 1988 Report to Congress, she testified that Duke reasonably and prudently would have believed that its unlined ash basins would not result in groundwater contamination at levels that would result in damage. She explained that the studies that were performed at Allen and Riverbend concluded that Piedmont soils, on which all of the Company's ash basins were located, were providing sufficient attenuation capability for coal ash leachate. (Id. at 217.)

In addition, she explained that the Company had also implemented groundwater monitoring at all of its plants before EPA issued its 2010 proposed CCR Rule. She testified that DEC was "way ahead" of the industry in terms of conducting groundwater monitoring at all of its ash basins, considering that the rest of the industry was only conducting groundwater monitoring in 42 percent of its ash basins by 2010. She also testified that, while the final CCR rule published in 2015 required groundwater monitoring at all unlined basins, facilities were not immediately required to install monitoring until later under the final CCR Rule. She reiterated that DEC was monitoring groundwater at all of its sites well before 2015. Witness Williams therefore opined that the Company's decision to continue to operate its ash ponds while waiting for the finalization of the CCR rule, and CAMA, was reasonable and prudent, as well as consistent with the performance of many other utilities that continued to operate unlined ash ponds, as noted in EPA's proposed rule. (Id. at 206, 285; Tr. vol. 28, 23.)

Regarding the Company's prudence, witness Williams testified that with respect to the period prior to the enactment of CAMA and promulgation of the final CCR Rule, the Company took steps to evaluate the potential impacts of its ash ponds on groundwater and surface water. She stated she did not see any evidence that the Company was presented with a compelling environmental reason to act differently with respect to its management of CCR for which it is requesting recovery of its costs. Moreover, she stated that there are examples where, upon the existence of data indicating an environmental problem, the Company worked with North Carolina regulators to take appropriate action. Regarding the estimation of ash basin closure costs, she stated that any cost estimates might have difficulty meeting the criteria for recovery of costs that are known and measurable, since an accurate estimate would be difficult. (Tr. vol. 27, 138-39.)

Witness Williams then gave her general opinions regarding the testimony of Public Staff witness Junis, Sierra Club witness Quarles, and AGO witness Hart. First, she stated that in assessing whether DEC's historic actions regarding its management of CCR were reasonable and prudent, all three witnesses failed to use an appropriate methodology that considers all relevant information and factors. She explained that each witness incorrectly relied upon a single research study or statement in a report (which does not represent consensus that a particular activity is or is not reasonable), instead of considering all available information. (Id. at 140.)

In contrast to these witnesses, she testified that a weight of evidence approach is the method she and other regulators used at the EPA in evaluating whether or not an activity warranted federal regulation and that this method should be the approach used when examining the historic reasonableness of a company's activities. She also stated that the three witnesses appear to downplay or overlook the role of regulations. Witness Williams testified that the fact that neither federal or state regulations mandated either the use of liners at surface impoundments or the installation of groundwater monitoring systems is an important input in assessing the reasonableness of DEC's historic activities, but neither witness Hart, Quarles, or Junis considered this factor. Finally, she found that the three witnesses do not assess in any detail the state or industry practices in either the utility industry or in other waste-generating industries. She testified that in her almost 50 years of environmental experience, even in the absence of regulations, it is very unusual to see large parts of an industry continue to handle waste in a manner likely to lead to environmental harm once knowledge of that environmental harm is generally confirmed. (Id. at 141-42.)

Second, witness Williams opined that all three witnesses fail to give appropriate weight to the role of DEQ in overseeing the Company's historic management of CCR.

She explained that the EPA worked closely to obtain state input into its 1988 CCR Report to Congress and into its work between 2000 and 2015 to evaluate minimum national protections for CCR. During these collaborative efforts, witness Williams testified that she was unaware that North Carolina indicated that it did not possess adequate authorities to protectively regulate CCR management. Moreover, she stated that DEQ had the ability to request that EPA use its authorities, if needed, to address any imminent and substantial endangerment. However, DEQ did not require DEC to modify the design of its ash ponds by requiring liners, did not require the ponds to close, or did not mandate groundwater monitoring earlier than they did, which she testified is a strong indication that DEC's operations were considered to be reasonable and protective by the Agency charged with protecting the North Carolina environment. (Id. at 143-44.)

Witness Williams then disagreed with Sierra Club witness Quarles' assertion that various historical documents "demonstrate that the environmental risk associated with the disposal of coal ash in unlined surface impoundments was understood by the electric utility industry in the late 1970s and early 1980s" and that DEC's operation of unlined surface impoundments in this timeframe "was unreasonable and could be expected to result in the introduction of CCR constituents to surface and groundwater." She testified that she could assure the Commission that if EPA's information did demonstrate a risk that was not being addressed by existing state regulatory authorities, EPA would have moved forward well before the final CCR regulation and recommended national minimum standards. (Id. at 144-46.)

Witness Williams also disagreed with witness Quarles' reliance on the 1979 AD Little Report, 1981 EPRI "Coal Ash Disposal Manual," 1982 EPRI "Manual for Upgrading Existing Disposal Facilities" and 1985 Arthur D. Little Study. She opined that these references, and many of the other references witness Quarles cites in support of his opinion as to the need for liners and groundwater monitoring systems prior to the 1990s, does not accurately portray the overall content of the documents, and that it is not appropriate to rely upon individual sentences in a report without providing a weight of evidence evaluation of the material in the report. (Id. at 153.) She also disagreed with Public Staff witness Junis' assertion that these materials were representative of the industry knowledge at the time they were published. (Id. at 207-08.)

Witness Williams also took issue with witness Hart's statement that "the utility industry, including DEC, knew about the potential for contamination from coal ash basins as early as the 1980s." She explained that his use of the word "potential" is overbroad and that his opinion does not inform as to what actions should or should have not been taken by the Company at any particular facility. She also testified that witness Hart, similar to witness Quarles, supports his opinion by selectively referencing documents and failing to recognize the general conclusions of the documents or context of the overall information and understanding in existence at that time. She testified that witness Hart incorrectly relied upon and characterized the March 1980 EPA and TVA Report, 1988 Report to Congress on CCR, and November 1991 EPRI Report in his testimony. (Id. at 155-57.)

In addition, witness Williams testified that witness Hart's assertion that DEC acted imprudently by submitting monitoring data to DEQ is inconsistent with her experience as a government regulator and that the prompt and complete submission of monitoring data is actually indicative of a prudent company. She also disagreed with witness Hart's assessment of costs, which she stated ignores the potentially significant unwarranted costs DEC or any utility may have incurred if it conducted closure activities prior to having the regulatory certainty that came with CAMA and the federal CCR. She testified that after the Company initiated groundwater monitoring at all of its sites by 2008, it continued to work with DEQ in an iterative fashion to improve the monitoring system to determine what, if any, remedial actions would be necessary or appropriate. She explained that this evaluation process can take many years, because developing an understanding of a complex subsurface environment is not easy. In her opinion, there was not more that the Company should have done, because a full understanding of the groundwater conditions is a predicate to reaching a final determination on the appropriate remedy. (Tr. vol. 29, 64-66.) Given the work that DEC was doing in conjunction with DEQ to monitor groundwater at its sites beginning under the USWAG Action Plan, she testified that DEQ would have eventually gathered enough information to decide the fate of the Company's ash ponds, even had EPA never finalized the CCR Rule. However, she testified that given the sophisticated groundwater modeling that is required to make decisions today, it is not realistic to suggest that DEQ could been able to reach a final decision before the passage of the CCR Rule in 2015. (Id. at 67-68.)

Lastly, witness Williams took issue with witness Junis' assertion that DEC's had had a specific number of groundwater exceedances "in violation of the state's 2L" rules. She explained that the 2L standards are water quality remedial requirements that recognize that environmental contamination, including contamination that constitutes environmental harm, can result when an entity is in full compliance with all operational performance requirements. She clarified that remedial standards, like those contained in the 2L Rules, differ from design, construction, and operational standards that are contained in permits issued by DEQ, like NPDES permits. She explained that it was the responsibility of regulators to ensure that design and operational standards were adequate to meet performance, or remedial standards, like the 2L Rules. She testified that regulators normally do not issue permits if they believe there is some unprotected condition associated with permits that they are about to issue. (Id. at 192-93.)

She testified that witness Junis' statement regarding the number of so-called "violations" DEC has received" is misleading and entirely based upon how frequently the Company conducted groundwater sampling. She stated that using witness Junis' approach of counting each sample of each substance that exceeded a standard as a violation disincentives entities for sampling frequently or comprehensively, which is an important reason why such exceedances are not treated as "violations" with associated penalties. She also testified that witness Junis' analysis was flawed because he assumed that groundwater is constantly moving, and that every exceedance represents the contamination of previously uncontaminated groundwater. She explained that groundwater plumes do not act in the manner witness Junis described; groundwater plumes are relatively static and typically stabilize, which is what has occurred at DEC ash basins, according to witness Wells. She concluded by noting that similar to witness Quarles and Hart, witness Junis had also unreasonably relied on several documents in support of his arguments regarding available knowledge on ash ponds and groundwater in the early 1980s. (Id. at 63-65; 233-34; 277-78.)

The Company submitted the supplemental rebuttal testimony of witness Williams to respond to AGO witness Hart's supplemental testimony calling for disallowances.[16] She explained that his contention was unsupported, and his attempt to estimate costs speculative and reliant on faulty assumptions. She also explained that witness Hart ignored potential scenarios that could have increased overall costs, and gave several examples of scenarios that could have increased costs for DEC. (Id. at 174-84.)

Rebuttal Testimony of Erik Lioy

DEC submitted the rebuttal testimony of Erik Lioy to respond to the Supplemental Testimony of AG witness Hart. The purpose of witness Lioy's testimony was to demonstrate that witness Hart's disallowance recommendation did not correctly utilize the time value of money methodology and was therefore flawed and inconsistent with generally accepted financial accounting practices. (Tr. vol. 22, 162-63.)

Witness Lioy testified that he is a Certified Public Accountant (CPA), licensed in the state of North Carolina, and that he is a Certified in Financial Forensics (CFF), Certified Construction Auditor (CCA), Certified Global Management Accountant (CGMA) and Certified Fraud Examiner (CFE). He testified that he has over 25 years of professional experience performing a wide range of accounting and financial analyses in connection with litigation, regulatory and other matters. He explained that he has extensive experience preparing calculations and performing hundreds of analyses using the time value of money concept. (Id. at 161-62.)

In preparing his rebuttal testimony, witness Lioy testified that he reviewed witness Hart's pre-filed direct testimony, witness Hart's supplemental testimony, witness Hart's deposition testimony in this case, and witness Hart's workpapers, including a spreadsheet submitted by the AG containing witness Hart's calculations (DEC Cost Reduction Spreadsheet). Based on his review of the relevant materials, witness Lioy concluded that witness Hart's testimony and calculations supporting the AG's recommended disallowance were flawed and unreliable, because they demonstrate a fundamental misunderstanding of – and, therefore, a misapplication of – the concept of time value of money. (Id. at 163-64.)

Witness Lioy explained that the "time value of money" is a financial concept used to value a sum of money at different points in time. He testified that the underlying premise of the concept is that when comparing sums of money over different periods of time, you need to factor in potential earning power of the money. By way of example, witness Lioy

[16] (Tr. vol. 16, 825.)

testified that if one can earn 5% annual interest, a dollar today will be worth $1.05 in a year from now. He explained that the inverse is also true: a dollar a year from now is a worth approximately $0.95 today. (Id. at 164.)

Witness Lioy then explained how witness Hart incorrectly applied the time value of money concept. He testified that under witness Hart's calculation, $343 million in today's dollars (ignoring witness Hart's error of using 2014 instead of "today") is equivalent to $172 million in 1989 dollars. He opined then opined, to assert, as witness Hart does, that there is a "difference" between these figures actually results from an apples (1989 dollars) to oranges ("today's" – although actually 2014 – dollars) comparison. As witness Lioy explained, these amounts are equivalent, just expressed at different points in time. He testified that a correct apples-to-apples time value of money analysis would determine that those amounts, compared in constant dollars, are equivalent. Witness Lioy explained that witness Hart's analysis actually demonstrates this: in constant dollars, the difference between the cost of the work had it been performed in 1989 ($172 million in 1989 dollars or its equivalent in today's dollars, $343 million) and the Revised Cost is ZERO. Witness Lioy testified that the result would be the same for the other dates selected by AG witness Hart (*i.e.* 1995, 2003, and 2010). Witness Lioy testified that witness Hart ignored that the point of calculating the time value of money is to make things equivalent, so that a comparison of costs at different time periods can be made using constant dollars. (Id. at 168.)

Witness Lioy opined that if witness Hart was attempting to quantify the amount DEC would have spent as of the earlier time periods in his analysis (1989, 1995, 2003, and 2010) in an attempt to quantify alleged imprudently incurred costs, witness Hart failed. He testified that all Witness Hart did is make a mathematical calculation by subtracting the Revised Cost (expressed in earlier period dollars) from the Revised Cost (expressed in "today's" – actually 2014 – dollars). Witness Lioy noted that witness Hart admitted at his deposition that he "didn't know of" any standard texts or peer reviewed journals that supported his application of the time value of money concept in this fashion, indicating that his methodology was just subtraction. (Id. at 169.)

Witness Lioy also testified that witness Hart failed to consider a number of necessary factors that he would need to determine what DEC would have spent in 1989, 1995, 2003, or 2010. He testified that to fully evaluate work that would or could have been done in 1989, for example, would require the evaluator to take into account different applicable laws and regulations in 1989 as compared to today, and different technologies, means and methods available in 1989 as compared to today, among other potential factors bearing on cost. Witness Lioy notes that witness Hart does not even attempt to do this – indeed, he indicates that doing so presents many difficulties, including the difficulty "at this point in time to retroactively determine what costs would have been incurred or more years ago." (Id. at 170.)

Setting aside witness Hart's misapplication of the time value of money concept, witness Lioy opined that witness Hart made numerous other errors that render his testimony unreliable. Witness Lioy testified that witness Hart erroneously took costs incurred between January 1, 2018 and June 30, 2019, and treats them as being incurred on a single day, December 31, 2014. He explained that witness Hart then discounted those costs back to January 1 of each of his selected dates. By treating costs in 2018 and 2019 as occurring in 2014, witness Lioy opined that witness Hart completely ignored the time value of money concept. Witness Lioy explained further that witness Hart's approach of assuming all costs (hundreds of millions of dollars-worth) occurred on a single day for purposes of his calculation defies reason and normal convention where the costs are incurred and spread out over multiple years as major projects are constructed and completed. Taking these factors into consideration, even if one were to accept his flawed methodology, witness Lioy opined that witness Hart's calculations are wholly unreliable, not prepared in accordance with normal accounting or financial conventions, and are wholly speculative. (Id. at 171-72.)

Rebuttal Testimony of Rudy Bonaparte

DEC submitted the rebuttal testimony of Rudolph Bonaparte to provide his observations and findings regarding CCR management strategies and closure planning of CCR surface impoundments in the Southeast region where DEC operates, including the states of Georgia, North Carolina, South Carolina, and Virginia, during the approximate timeframe of 2009 to 2011, or earlier. (Tr. vol. 11, 821.)

Witness Bonaparte testified that he is registered professional civil engineer in 19 states and is the Chairman and a Senior Principal with Geosyntec Consulting, Inc. and has nearly 40 years of professional experience in the areas of geo-environmental and geotechnical engineering applied to municipal, industrial, hazardous, and low-level radioactive waste disposal facility projects. He explained that his experience with CCR landfills and impoundments spans 25 years, and that he is knowledgeable regarding the physical and chemical characteristics of CCR, the Federal CCR Rule, and the design and construction of storage, disposal, and closure systems for CCR. (Id. at 819-20.)

Witness Bonaparte testified that his findings were based on two sets of publicly available documents for coal-fired electric power plants for these states: (1) reports presenting the results of safety assessments for CCR impoundment dams prepared by private engineering firms under subcontract to the USEPA in the timeframe 2009-2011 (USEPA dam safety assessment reports); and (2) for the CCR impoundments identified in the USEPA dam safety assessment reports, closure plans prepared by the utility owners/operators of the CCR impoundments (or their consultants) in or around 2016 pursuant to the Federal CCR Rule (40 CFR § 257.102(b)). In a few instances, the posted closure plans were prepared pursuant to state regulations rather than the CCR Rule; for his report, these facilities are considered together and collectively referred to as CCR Rule closure plans. Witness Bonaparte compiled his findings in a report dated March 2020 titled, "CCR Surface Impoundment Public Information Review," which he provided as Exhibit 2 to his rebuttal testimony. (Id. at 821.)

Witness Bonaparte testified that, from the USEPA dam safety assessment reports, he recorded information regarding each CCR impoundment's location, year built, report preparer (engineering consultant), active/inactive status, lined or unlined condition, operating information, and most relevant to our report, whether there was any indication in the report that planning for, or implementation of, an engineered impoundment closure had occurred prior to or during the 2009-2011 timeframe. He testified that, from the CCR Rule closure plans, he recorded information about each CCR impoundment's closure plan date, closure plan preparer, closure method (e.g., closure by removal, cap-in-place), details of the closure cover system, actual or anticipated closure construction start date, and whether the CCR Rule closure plans referenced or mentioned prior closure plans (in or prior to the 2009-2011 timeframe) and/or any earlier closure planning or closure construction activities. (Id. at 821-22.)

Witness Bonaparte's report indicates that his review included the CCR impoundments at an estimated 40 of the 50 generating stations in Georgia, North Carolina, South Carolina, and Virginia (80%). He noted that USEPA dam safety assessment reports were not prepared for some generating stations because CCR at the stations were being disposed in landfills and not surface impoundments (and thus there were no dams to assess). Witness Bonaparte provided the following summary of his review:

- Information was reviewed for 93 CCR impoundments at the 40 generating stations. Of these, only three (3.2%) CCR impoundments were identified as having engineered closure plans and/or engineering-related closure planning in the 2009-2011 timeframe, or earlier. A few additional impoundments had received a layer of non-engineered fill above the CCR impoundment and/or had grass/vegetation growing on the surface of the impoundment, but this non-engineered closure activity is interpreted herein as being a simple extension of CCR impoundment operations.

- Of the 93 CCR impoundments reviewed, 85 (91%) were either directly reported or interpreted as being unlined; most of the CCR impoundments reviewed were reported as being active in the 2009-2011 timeframe (although some were inactive), and of the active impoundments, the majority were reported as receiving sluiced CCR at the time of the USEPA dam safety assessment reports.

- Only 1 of the 57 CCR Rule closure plans had any indication of closure planning for the subject CCR impoundment for the 2009-2011 timeframe, or earlier.

(Id. at 819; DEC Bonaparte Rebuttal Exhs. 2, 9.)

Rebuttal Testimony of Jessica Bednarcik

In her rebuttal testimony, witness Bednarcik rebutted the prudence-based and culpability-based disallowances recommended by the Public Staff and AG, including:

(1) payment of a fulfillment fee to Charah related to the disposal of ash from the Riverbend plant at the Brickhaven structural fill ($46,142,699); (2) payment of “premium rates” for ash excavation and disposal at the Dan River Steam Station ($29,250,905); (3) construction costs at the Buck Beneficiation plant ($67,809,160); (4) expenditures for groundwater extraction and treatment at the Belews Creek plant ($298,433 on a system basis); and (5) costs incurred to connect eligible residential properties to permanent alternative water supplies ($16,882,665 on a system basis) and/or install and maintain water treatment systems ($962,524 on a system basis). She also discussed, in supplemental testimony requested by the Commission, the Company’s projected future costs of basin closure.

4. Charah Fulfillment Fee

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**

In an attempt to mitigate the risk that Charah might not recover all or part of its capital expenditures in the event of termination or any significant decrease in the amount of ash to be excavated, the parties agreed to the fulfillment fee provisions. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]** Ultimately, however, the Company only issued purchase orders for 7,342,409 tons of ash to be delivered to the Brickhaven mine. This was the result of changes to Duke Energy's closure strategy mandated by amendments to CAMA requiring beneficiation that were passed *after* execution of the Charah Master Contract and issuance of the first purchase order. Witness Bednarcik explained that the fulfillment fee was subsequently calculated and paid according to the detailed terms of the contract. (Id. at 55.)

5. Dan River Costs

With respect to the costs the Company incurred to excavate ash at Dan River, witness Bednarcik explained that the Company could not have foreseen the delays that Parsons faced and its inability to effectively deal with them. Accordingly, to meet the CAMA deadline, the Company contracted with Trans Ash to complete the Dan River excavation work. (Id. at 65-66.) Moreover, the mitigating strategies witness Garrett proposes—including negotiation of a performance bond, and requests to collect security and back charges from Parsons—are not reasonable and demonstrate a fundamental misunderstanding of these contractual terms. (Id. pp. 69-71.)

Witness Bednarcik testified that Parsons encountered a variety of delays that slowed its excavation work. For example, in May 2018, Parsons landfilled ash that did not meet moisture content specifications and thus necessitated significant rework. That same incident, witness Bednarcik explained, caused a subsequent breach in the landfill that required weeks of remediation. In addition, Parsons' operations were impacted by even the smallest amount of precipitation (rainfall of less than .2 inches in a 24 hour period caused a day-long shutdown of excavation work). Finally, Parsons routinely took longer than anticipated to complete its scheduled work due to short staffing and poor coordination of subcontractors and equipment suppliers. (Id. at 64-65.)

Witness Bednarcik explained that the Company actively worked with Parsons to address and remediate the continued delays to the CCR excavation project, including by asking Parsons to prepare and implement various Recovery Plans (pursuant to the contract) and facilitating discussions with the leadership team at the Sutton ash excavation site. While some of the actions within the Recovery Plans resulted in schedule gains, the net impact of Parsons' strategy did not recover the schedule, and Parsons fell even further behind the planned completion date. (Id. pp. 65-66.) To complete excavation by the CAMA deadline, the Company contracted with Trans Ash, which had demonstrated a successful track record at Sutton. Trans Ash, in turn, initiated a 24/7 construction schedule in January 2019.

Witness Bednarcik explained that witness Garrett's cost mitigation strategies demonstrate a misunderstanding of the contractual terms he references. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted] **[END CONFIDENTIAL]** Last, if the Company did not terminate the Parsons contract, Parsons—like Trans Ash—would have had to expend additional resources to condition the ash (e.g. increased working hours, and use of a material like lime to condition the ash) to meet the CAMA deadline.

Finally, witness Bednarcik testified that seeking an extension to the CAMA deadline would not have saved any of the challenged costs. Witness Bednarcik explained that there is no guarantee extension requests will be granted (in fact, DEQ declined to grant the full extension requested at Sutton); and, in any event, the Company would have been required to continue with the accelerated excavation schedule while awaiting a response from DEQ, which likely would have taken several months. (Id. at 78.)

6. Buck Beneficiation Costs

With respect to the Buck beneficiation site, witness Bednarcik testified that the RFI promulgated by the Company in August of 2016 for the Buck beneficiation project did not ask responding contractors for any site-specific estimate of the EPC costs to be incurred for the beneficiation sites, nor did it provide project details that would be necessary to calculate such an estimate – in large part because the Company was still developing the project's precise scope and determining the locations for beneficiation. Nevertheless, the Company still intended to engage H&M to construct the beneficiation units based on its past work with SEFA, but H&M ultimately removed itself from consideration for the project. (Id. pp. 80-82.)

Witness Bednarcik explained that the estimate SEFA provided was based on the costs it incurred to construct the Winyah STAR Facility in South Carolina, but there are several key differences between the Winyah and Buck projects that would impact cost. (Id. at 82.) First, the Winyah plant is designed to produce 200,000 tons of ash product per year (a 120 MMBtu facility), while the Buck beneficiation unit must produce 300,000 tons of ash product per year (a 140 MMBtu facility) to meet CAMA requirements. CAMA's output requirement necessitated installation of a second external heat exchanger at Buck along with all associated equipment. In addition, Winyah typically uses 70 percent ponded ash and 30 percent production ash. Ash at the Company's plants, on the other hand, is 100 percent ponded ash and required the addition of a grinding circuit to meet American

Society for Testing Materials (ASTM) standards for concrete. The two facilities also use different scrubbers, and the dry scrubbers at Buck required a second bag house with additional induced draft fans. Finally, the Winyah STAR facility was a refurbishment/addition to an existing carbon burn-out facility and SEFA was able to reuse a significant part of the carbon burn-out facility when constructing Winyah's STAR unit. The Company's facilities are new construction. (Id. at 84.)

According to witness Bednarcik, after H&M declined the project, in January 2017, the Company sent out an RFP for the balance of plant engineering and construction to four Companies – CBI, Fluor, Kiewit, and Zachry. Each of these companies were engaged in current EPC contracts with the Company and/or had successfully worked with the Company in the past. Because the detailed engineering had not begun and one of the three locations had not been selected, the RFP evaluation was based upon labor and equipment rates, not on overall estimated construction costs. Accordingly, the Company selected Zachry based upon its stated rates and not on any overall estimated contract price. In fact, after the Company selected Zachry as the EPC contractor in February 2017, the Company's internal estimating group worked with Zachry to develop an estimated overall cost, which was the amount included in the Zachry Master Contract 21281, dated November 3, 2017. (Id. at 86.)

Witness Bednarcik stated that witness Moore's suggestion that the Company should have sought statutory relief from CAMA's beneficiation requirements is not a real world solution. First, there is no guarantee that the General Assembly would have actually granted such relief. Even if it did, it is like that the original CAMA deadline would have passed before such a bill could be drafted, vetted, and passed. Witness Moore's suggestion that the Company should have sought guidance from DEQ upon learning of Zachry's estimated EPC costs is also misguided. DEQ is responsible for enforcing the State's environmental laws irrespective of an entity's cost of compliance. There are no cost considerations in the beneficiation provisions of CAMA and it would therefore be inappropriate for DEQ to make such considerations as part of its enforcement. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

7. Extraction Wells and Groundwater Treatment

In response to witness Junis' proposed disallowance of these costs, witness Bednarcik noted that the Commission allowed the Company to recover these same types of cost in the Company's last rate case. She further discredited witness Junis' claim that the Company identified 3,972 instances of "groundwater violations" by explaining that an increase in measured exceedances does *not* suggest an increase in groundwater contamination in and around the Belews Creek plant. Rather, it is simply an indicator of the increased testing—both in frequency and location—the Company is conducting to identify the location of the plume. (Id. at 91-93.)

8. Permanent Alternative Water Supplies

Finally, witness Bednarcik argued that the Commission should allow the Company to recover its costs related to permanent alternative water supplies and the costs to install and maintain water treatment systems because these costs were incurred pursuant to statute and, as witness Junis acknowledged, there has been no change since the Commission allowed recovery in the 2017 rate case. (Id. at 50-51.)

9. AG's Proposed Disallowance

Witness Bednarcik submitted supplemental rebuttal testimony to address certain issues raised in the supplemental testimony of AG witness Hart. In particular, she testified that witness Hart failed to recommend any concrete disallowance and instead simply contends that the Commission should impose a disallowance ranging from $50 million to $190 million to reflect potential cost savings had the Company completed closure. Witness Bednarcik explained that witness Hart's testimony is flawed on many levels. First, it failed to consider that the Company might have chosen a different closure strategy had it undertaken the task at an earlier date. Witness Bednarcik testified that any analysis of what strategy the Company would have adopted or what costs the Company would have incurred had it chosen to close inactive basins in 1989, 1996, 2003, and/or 2010 would have been nothing more than conjecture. (Id. at 106-107.)

10. Projected Future Closure Costs

Witness Bednarcik submitted supplemental testimony to respond to the Commission's July 23, 2020 Order Requiring Duke Energy Carolinas, LLC and Duke Energy Progress, LLC to File Additional Testimony on Grid Improvement Plans and Coal Combustion Residual Costs. In response, witness Bednarcik provided spreadsheets showing (1) the projected annual CCR remediation costs on a plant-by-plant basis from 2019 through 2078,; (2) for each plant and year, a breakdown of the costs by remediation activities; and (3) for each plant's annual total cost an allocation to North Carolina retail based on the applicable energy factor. (Id. pp. 108-110.)

Witness Bednarcik also provided a brief explanation of the Settlement Agreement the Company reached with DEQ and a variety of special interest groups represented by the Southern Environmental Law Center (SELC) regarding closure of the Company's remaining ash basins. Witness Bednarcik explained that the Agreement details a reasonable and prudent plan for closure of the nine remaining CCR basins owned by DEC and DEP. Seven of the nine basins—including two at the Allen Steam Station, one at Belews Creek Steam Station, one at the Mayo Plan, one at the Roxboro Plant, and two at the Cliffside Energy Complex—will be excavated in their entirety with ash moved to on-site lined landfills. For the other two basins, at Marshall Steam Station and the Roxboro Plant, uncapped basin ash will be excavated and moved to lined landfills. While Duke Energy agreed to excavate all remaining ash rather than cap it in place, witness Bednarcik explained that the Company also secured key representations from DQ and the community and citizen groups that would allow it to proceed with excavation as expeditiously as possible and without the threat of further challenges from either group. In particular, witness Bednarcik explained that the Agreement calls for expedited state permit approvals, which would keep projects on a rapid timeline, while at the same time reducing the total estimated cost to close the remaining basins by roughly $1.5 billion as compared to the April 1, 2019 DEQ order requiring full excavation at all sites. Entering into the Settlement Agreement also allowed the parties to resolve other pending litigation in state and federal courts, thereby ensuring that the impoundments are excavated on an expedited basis and to remove the uncertainty associated with litigation. (Id. at 112-14.)

Witness Bednarcik explained that the Company did not incur any incremental cost as a result of the Settlement Agreement with respect to the costs it is seeking to recover in the instant rate case. With the exception of closure plan development, none of the site work that has been conducted at the Allen, Belews Creek, Cliffside, or Marshall sites is specific to cap-in-place closure and would be required to complete closure by excavation as well. (Id. at 115.) That said, witness Bednarcik explained that it would be impossible to identify with any degree of certainty the incremental costs that the Company is likely to incur as it proceeds to excavate, rather than cap-in-place, its remaining CCR basins. Aside from the expected margin of error surrounding estimates for both closure methods, it is difficult to assign a dollar value to the efficient regulatory approval process the Company secured through the settlement. (Id. at 116.)

Rebuttal Testimony of Doss, Riley & Spanos

Witnesses Doss, Riley, and Spanos testified regarding a number of coal ash accounting issues. These witnesses rebutted the Public Staff's positions regarding ARO accounting employed by the Company for its CCR basin closure costs, and, in particular, witness Maness' characterization of those costs as a deferred expense. witness Doss highlighted that the Commission comprehensively addressed witness Maness' position on ARO accounting and deferral issues in the 2018 Rate Order. Witness Doss noted that the Commission rejected Public Staff witness Maness' testimony and credited the testimony of Company witnesses Doss and McManeus. Witness Doss testified that, as this Commission concluded in the 2018 Rate Order, "witness Maness' classification of these costs as "deferred expenses" is not persuasive, not supported by authority and not determinative given the nature of deferral and it is also incorrect as a matter of accounting. (Tr. vol. 22 at 234.) Witness Doss noted further that he provided detailed testimony in the Docket E-7, Sub 1146 explaining the GAAP, FERC and deferral requirements governing the Company's established of an ARO for CCR basin closure costs. In the 2018 Rate Order, the Commission expressly credited his explanation on these issues and found his testimony uncontradicted in that case. (Id. at 229.)

Witness Doss explained further that relying upon guidance from this Commission, ASC 410, GAAP, FERC, and Duke Energy Corporation accounting policies, the ARO charging committee rigorously evaluates costs to be incurred to determine whether they qualify for ARO accounting treatment. (Id. at 248-49.) The charging committee's designations are internally reviewed by the Company's "Coal Combustion Products ("CCP") group to ensure that 1) all relevant facts were appropriately communicated by CCP and understood by the Committee, and 2) that the CCP group understands the decisions to properly categorize actual project costs. (Id. at 248-49.)

Importantly, the purpose for which costs are incurred determine the corresponding classification. Witness Doss demonstrated this point during live testimony at the DEP hearing:

> Q. Now. What effect does the purpose for which costs are incurred have upon the proper classification of costs?
>
> A. Well, it's everything. You know You know, I – in reading through this, what the witness for Dominion said, that these were services and labor costs, there seems to be an implication there that because it's services and labor, that somehow defines it as operation and maintenance, which couldn't be further from the truth. As I've said in my supplemental testimony, we need to know what the purpose of that services and labor is for And I can give examples. For instance, at our company, if I'm at a warehouse and I see a truck leaving a warehouse with some materials and supplies and it's going to a job site, I don't know whether that's expense or that's capital in nature. I need to know what the purpose for that is. For instance, it's going to a job site where they're doing some repair of a distribution line after a storm; that's an expensed activity, and therefore, the cost of that truck rolling out carrying the materials, the person driving the truck, all those costs would be considered expense
>
> However, I could see another truck leaving from that same facility also with a driver in the truck, some materials in the truck that's going to, for instance, a site where we're building a generation plant. Same activity, but the purpose is for a capital construction project, and that cost can be charged to capital.

(DEP Tr. vol. 17, 45-46.)

Regarding potential subdesignations of ARO costs to reflect how DEC would have accounted for costs if such costs were not capitalized, witness Doss reiterated that in the 2018 Rate Order, the Commission found that under GAAP, the costs (no matter what their classification), are capitalized pursuant to ASC 410-20-25-5. (Id. at 249-250.) To that end, DEC simply cannot reconstruct accounting systems, processes, and guidelines that would apply in a hypothetical non-ARO accounting world: "[n]ot only is DEC' accounting system incapable of facilitating a retroactive removal of accounting guidance, a retroactive assessment of what designation other than ARO might be appropriate for a particular activity would be pure speculation." (Id. at 251.)

In response to questions by Commissioner Hughes, witness Reilly put the concept in more concrete terms. He noted first that if the Company is actually in an "out-of-pocket cash" situation and it receives less than a full return then "that would be viewed as being a disallowance" (Tr. vol. 23, 174-75) – an "implicit" disallowance (Tr. Vol. 24, 37), but a disallowance, nonetheless. Commissioner Hughes posed a hypothetical in which "$500 million was sought … and $500 million was granted, but over a period of time that caused a net present value disallowance." (Id., 20). Witness Riley's response captures the impairment caused by the loss of the return in terms of the accounting for the loss, but it also illustrates the impairment of earnings implicit in the disallowance:

> [I]n your example, if the Company's seeking $500 million in recovery and they're granted $500 million in recovery, except if the Company is out-of-pocket cash today $500 million and they're not going to recover that for, say, a period of time, call it 25 years, they have used shareholder monies today, and shareholders expect a return on the use of their funds.
>
> So to the extent that the Commission were to only grant recovery over a 25-year period … in present value dollars it's something less than $500 million.
>
> And what the accounting would require is for the Company to assume or to assess what return would it have expected to get on those dollars, and I would have expected weighted average cost of capital. They would present value of those dollars back to today's dollars to today. Using your example, say that discounts back to $400 million. They would take a charge of $100 million for that implied disallowance in accordance with the accounting standard.
>
> So, in effect, because they're not getting a return on their money, that has to be recognized today as a charge.

(Id. 20-21.)

Witness Riley also discussed the requirements of ASC 420, which beginning in 2003, required companies like DEC to assess, on an ongoing basis, whether it had a present legal obligation to remove, dispense, or remediate a long-lived capital asset.

Framework for Discussion

This Commission has specific duties and functions delegated to it by statute. "The Commission is a creation of the Legislature and, in fixing rates to be charged by public utilities, exercises the legislative function. It has no authority except that the [authority] given to it by statute." *Edmisten III*, 291 N.C. at 464. This Commission is not an environmental agency, charged with the enforcement of the nation's or this State's environmental laws. It is not a law enforcement agency, either. Nor is it a court of general jurisdiction, endowed with the responsibility to pass on issues of tort liability or due care under the circumstances. Rather, it sits in this proceeding with a specific task: To determine just and reasonable rates that the Company may charge its customers. In fixing such rates, the Commission is further charged with the task of examining and assessing the Company's costs, upon which those rates are founded.

The Commission concludes, based upon its careful review of all the evidence presented and its application of the governing legal principles to the facts that it has determined to be pertinent that the Company has met its burden of showing that the CCR Costs it has and is incurring *are* known and measurable, reasonable and prudent, and used and useful in the provision of electric service to customers. As such, the Commission finds and concludes as follows:

- DEC seeks recovery of the actual CCR costs it incurred during the period from January 1, 2018 through January 31, 2020, On a North Carolina retail jurisdiction basis, these costs amount to approximately $342 million.[17] These costs are (a) known and measurable, (b) reasonable and prudent, and (c) used useful in the provision of electric service to the Company's customers. As under N.C. Gen. Stat.§ 62-133 – the statute governing "How rates [are] fixed" in North Carolina – these costs are required to be included in rates, and the Commission may not legally disallow them. However, the Company proposes that, rather than recovering 100% of these already incurred costs immediately, it recover them over a five-year amortization period. The proposed five-year amortization period is just and reasonable, fair to the Company and to its customers, and the Commission approves it.

- DEC seek to recover the financing costs incurred during the Deferral Period and the Amortization Period. The Deferral Period is the period from the time the costs were first incurred through the date upon which they begin to be brought into rates. The Amortization Period is the period over which deferred CCR Costs are amortized – that is, paid by customers over time – as they are brought into rates. The financing costs equate to a return "on" prudently incurred CCR costs. They are allowable and allowed.

In short, the Company has met its burden – both the prima facie burden of production and the ultimate burden of persuasion – of showing its entitlement to a recovery "of" CCR Costs. The Company having met that burden, it is entitled under the applicable legal standards to a return "on" such Costs at its weighted average cost of capital that the Commission sets in this case.

In remaining sections of this Order, the Commission explains and provides the basis for its decision. The Commission deals with four basic questions:

1. Whether Intervenors' "fault"-based theories of disallowance, and specifically the Public Staff's "equitable sharing" proposal, are viable under the law. The Commission answers this question "No."

[17] The remainder of DEC's cost recovery request in this case (approximately $378 million) consists of financing costs incurred during the Deferral Period through July 2020.

2. Whether Intervenors cost disallowance proposals that apply to the Company's historical actions and decisions – that is, actions and decisions taken long before, and in some cases decades before, the time period in which the costs sought for recovery in this case were incurred. Viewing these actions and decisions through the lens of the prudence framework, the Commission again answers this question "No" – to the contrary, applying the prudence framework Intervenors' challenges fail, because (a) Intervenors have not quantified the impact of the Company's actions and decisions upon customers, and (b) in any event, the Company has shown that its actions and decisions were prudent in light of industry standards and knowledge at the time they were taken and made.

3. Whether a return on any costs to be recovered is allowable. The Commission answers this question "Yes." For prudently incurred CCR Costs that investors advanced to customers, DEC is entitled to earn a return during both the Deferral Period and the Amortization Period at its authorized weighted average cost of capital established in this case. This determination is consistent with the mandates of the Constitution, the rate fixing statute, decisions of the North Carolina Supreme Court, and the spend/defer/recover framework established in the 2018 Rate Order.

4. Whether the prudence-based challenges to the Company's coal ash costs, or other discrete challenges mounted by the Public Staff and the Attorney General's Office (AGO) should be allowed. The Commission answers this question "No." The Company has carried its burden of proving that the costs are prudently incurred.

Discussion of Question #1: "Fault"-Based Theories of Disallowance, and Specifically "Equitable Sharing"

The Commission has already indicated in its introduction to the coal ash section of this Order that Intervenors' "fault"-based concepts are not viable cost disallowance mechanisms under North Carolina law. Here the Commission discusses in detail the principal "fault"-based theory – the Public Staff's "equitable sharing" concept, and also the Public Staff's specific "fault"-based claims relating to the Company's environmental practices, as they relate to seeps and groundwater exceedances.

"Equitable Sharing"

Intervenors' principal "fault"-based theory is advanced by the Public Staff. Slightly over three years ago, when the Public Staff filed testimony in DEP's last rate case, it unveiled its theory of "equitable sharing,"[18] whereby it proposed that a substantial portion of coal ash costs – *costs which it could not classify as having been imprudently incurred*

[18] That testimony was filed on October 20, 2017.

– be shared 50/50 between DEP and its customers, based on some (undefined) degree of DEP's "culpability" for the incurrence of those costs. It proposed the same theory, albeit with a different sharing ratio (51/49, in favor of customers) in DEC's last rate case. It proposed the same theory, with yet a different sharing ratio, in Dominion Energy North Carolina's (Dominion) last rate case – 60/40 in favor of Dominion. In each one of those cases the Public Staff asserted that adoption of the theory, and of the Public Staff's chosen sharing ratio, was within the Commission's discretion. In each one of those cases the Commission rejected the theory, indicating that the theory was arbitrary and, were it to be adopted, would expose the Commission to attack for imposing an arbitrary and capricious disallowance of costs. In this case, the Commission again rejects the Public Staff's "equitable sharing" theory as arbitrary

Assessing alternatives and quantifying costs are hallmarks of the prudence framework. The Public Staff concedes, therefore, that no disallowance of CCR Cost under the prudence framework would be permissible, except of course, through a Garrett and Moore-type prudence analysis. In this case the Public Staff once again advances its theory, asking the Commission to "take a fresh look" at its arguments. (Tr. Vol. 20, 469.) The Commission declines Public Staff's invitation. There is no need for a "fresh look" – the Public Staff's theory is today just as arbitrary as it was when the Commission rejected it in the Company's prior case:

> First, the concept is standard-less, and, therefore, from the Commission's view arbitrary for purposes of disallowing identifiable costs – there is no rationale that supports a substantially large 51% disallowance. The Public Staff chose a desirable equitable sharing ratio, then backed into the mechanism to achieve that level of disallowance, leaving the allocation subject to an arbitrary and capricious attack, particularly as it provides no explanation as to why the "equitable" split for DEP in the 2018 DEP Case was in its view 50-50, while the "equitable" split in this case is 51-49. As the Commission held in the 2018 DEP Case, the "Public Staff provides insufficient justification for the 50/50 [split] as opposed to 60/40 or 80/20 ...." 2018 DEP Rate Order, p. 189.

2018 DEC Rate Order, at 273. Citing to Black's Law Dictionary and *Tate Terrace Realty Investors, Inc. v. Currituck Cty.*, 127 N.C. App. 212, 222-23 (1997), the Commission noted that an "arbitrary and capricious" decision is one which, *inter alia*, is "without determining principle." (2018 DEC Rate Order, at 273.) It held that it could "discern no 'determining principle' in the Public Staff's 'equitable sharing' proposal" (*id.*), thereby subjecting itself to likely reversal were it to adopt the proposal.

Nothing has changed since the Commission wrote those words. The Public Staff followed the exact same methodology, described in witness Maness' testimony, as it did in the last case (and in DEP's last case, and in Dominion's last case) to create the sharing arrangement. First, witness Maness removed unamortized coal ash costs from rate base, thereby eliminating any return on that unamortized balance. (Tr. vol. 20, 502.) Next, he chose an amortization period that would result in the Public Staff's desired sharing ratio.

(Id., 514-15.)[19] In other words, just as it did in the Company's last case (and in DEP's last case, and in Dominion's last case), the Public Staff merely chose its desired sharing percentage, then mathematically backed into that percentage by using the amortization period as a toggle. It is the Public Staff's choice of the sharing percentage that is arbitrary and "without a discerning principle." Commissioner McKissick's request of the Junis/Maness panel to provide him with "standards" for "culpability" is a request that the Public Staff provide him with this discerning principle: "a standard that applies not simply to the facts of this case, but to other cases that the Commission might consider if they're going down the path of equitable sharing." (Tr. vol. 22, 39.) Despite having espoused "equitable sharing" and "culpability" for the past three years, the Public Staff is still unable to supply this discerning principle, as is evident from its submission of Public Staff Late-Filed Exhibit No. 1 (PS LFE No. 1).

The prudence framework is an established standard of conduct against which the utility's actions may be judged. Commissioner McKissick's request was for the Public Staff to articulate criteria by which the Commission could *objectively*, not *subjectively*, judge a utility's conduct, and, on the basis of that objective review, determine whether the utility's conduct merited a finding that some costs sought to be recovered should instead be disallowed. According to PS LFE No. 1, "equitable sharing" and "culpability" are grounded in the Commission's discretion, granted by N.C. Gen. Stat. § 62-133(d), to consider "all other material facts of record" in setting rates that meet the statutory mandate of being just and reasonable, and fair to the utility and the consumer. However, consideration of all other material facts "is not a grant to roam at large in an unfenced field." *State ex rel. Utilities Comm'n v. Pub. Serv. Co. of N. C.*, 257 N.C. 233, 237 (1962).

Commissioner McKissick asked the Public Staff to provide the fencing – the Public Staff's response, essentially, is that there is no fencing save the Commission's (unbridled) discretion.[20] PS LFE No. 1 does not articulate *any* rules, much less rules that can be objectively and generally applied to conduct beyond the facts and circumstances of this case. Rather, PS LFE No. 1 conclusively proves that the Commission's insight and holding from the 2018 DEC and 2018 DEP Rate Orders was exactly correct – "culpability" and "equitable sharing" are standard-less concepts without any consistent and objectively understandable rationale. To the contrary, they are merely expressions of the Public Staff's "judgment" as to how and in what ratio coal ash costs should be shared between the Company and its customers – an arbitrary and continuously fluctuating judgment of the Public Staff alone. Were the Commission to agree and adopt that judgment, it would

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[19] The choice of amortization period actually varied as witness Maness reacted to changing circumstances. In his initial testimony he recommended a 26-year amortization period that produced a customer sharing ratio of 50.4%, which the Public Staff considered "sufficiently close" to 50%. (Tr. vol. 20, 544-45.) Then, in his second supplemental testimony, he changed his recommendation to a 27-year amortization period that results in a customer sharing ratio of 49.7%, which the Public Staff considers "closer to 50% than [the alternative]." (Id.) These gyrations simply confirm the arbitrary nature of the process.

[20] In *State ex rel. Utils. Comm'n. v. Thornburg*, 314 N.C. 509, 516 (1985) the Supreme Court specifically warned that the Commission under Section 62-133(d) did not in fact have "unbridled discretion in exercising its judgment."

be acting no less arbitrarily. And for an administrative and adjudicatory body to act arbitrarily is, of course, contrary to law.

Environmental Practices – Seeps and Groundwater Exceedances

In PS LFE No. 1 the Public Staff asserts that the Company had "***some*** degree of fault" for past environmental practices. ((Id., at 1) (emphasis supplied).) It mentions specifically surface water discharge issues (seeps) as well as North Carolina's groundwater classification rules and standards, known as the 2L rules. Both subjects were addressed in detail in the Company's prior case, with the Public Staff's position being soundly rejected, yet both are revived again in this case. The Commission once again rejects both challenges.

The Public Staff insists that "unauthorized seeps that DEC has admitted to environmental regulators" violate the terms of the Company's NPDES permits. (Tr. vol. 20, 405.) To put it in tort-like terms, the Public Staff claims "unauthorized seeps" are evidence of the Company's "culpability" for environmental violations – the Company is at "fault" for those violations. Setting aside the fact that the Public Staff assigns no actual dollar impact to customers of these "violations," to equate seeps with management imprudence is simply wrong when addressed in the context of the actual story of the seeps.

That story was presented in detail by Company witness James Wells, and not contradicted by anyone. It covers multiple pages of his pre-filed testimony (see Tr. vol. 27, 58-62), and additional multiple pages of his hearing testimony. (Id., 298-306.) The short version is as follows. All earthen dams seep; indeed seepage is necessary to maintain the stability of the dam. Engineered seeps are designed to collect seepage within the dam structures. In 2010, EPA instructed the States with delegated authority under the Clean Water Act, which would include North Carolina, to evaluate seeps within the permitting process. DEC approached DEQ *at that time* with data regarding the seeps, and sought the agency's guidance on how to proceed. DEQ decided it had other more pressing priorities, particularly since the effluent composition of the seep water was similar to effluent from the ponds themselves, but in substantially lower concentrations, and also as no other state was following through with EPA's request. In 2014, four years after EPA tried to induce the States to address seeps but with no action on that subject taken by DEQ, and in an effort to seek regulatory certainty as to seeps, DEC sought to include all "areas of wetness" at its coal ash basins in its NPDES permits – and DEQ sat on the application for years. Eventually, in 2018 – *four years after DEC applied for the permits, and eight years after DEC first broached the issue with DEQ* – DEC and DEQ agreed on a regulatory approach as to seeps, which has now been implemented.

Apart from the story's ending – which had not yet happened at the time – witness Wells gave essentially the same testimony in the Company's last case. The Commission summarized this testimony in its Order:

> Company witness Wells testified on rebuttal … [in response to Public Staff witness Junis who] suggested that the existence of seepage at

> the Company's CCR impoundments is evidence of the Company's "culpability." Witness Wells explained that the Public Staff's position ignores (1) the fact that the EPA first directed permitting authorities to address seeps in 2010, (2) the Company's attempts to obtain regulatory certainty as to seeps, and (3) DEQ's challenges in implementing EPA's direction. Tr. Vol. 24, p. 226.

2018 Order at 250. The Commission in the prior case declined to view the seeps as evidence of mismanagement – because they are *not* evidence of mismanagement. Yet the Public Staff wants in this case to re-litigate the exact same issue, on the exact same theory, with the exact same evidence – and expects a different result. The Commission rejects this approach. Whether the existence of seeps – known by and disclosed to the environmental regulator, and the subject of long-standing negotiations between the Company and its environmental regulator regarding the best and most effective way of dealing with resulting environmental impacts (if any) – is in violation of the Clean Water Act is not an issue for the Commission. It is an issue for the environmental regulator, and was resolved by the environmental regulator. The questions for the Commission are (1) whether the existence of seeps constitutes mismanagement, and, if so, (2) what economic consequences of that mismanagement are to be visited upon the Company. The answers are (1) No, and (2) Not Applicable – and even if (2) were applicable, no one, and certainly not the Public Staff, has calculated any economic consequence *to* be visited upon the Company.

The groundwater story is much the same as the seeps/surface water story – the Commission dealt with this at length in its 2018 Order, and the Public Staff is once again simply wrong. First, the Public Staff's assertion of "culpability" or "fault" is based wholly on what it alleges are the large number of "violations" of the 2L rules. As witness Junis put it, there are "10,940 groundwater exceedances confirmed by DEC's own groundwater monitoring data, in violation of the state's 2L rules." (Tr. vol. 20, 405.) But relying upon a simple count of exceedances does not equate to mismanagement; rather, it constitutes "a very serious flaw in … [the] analysis [which is] misleading." (Tr. vol. 27, 277.)

Witness Junis' testimony is based upon a complete misapprehension of the facts. He indicates that the number of violations is a factor of sampling "new contaminants" because of movement of the contaminant plume. (Tr. vol. 21, 17.) Witness Williams, who is an actual expert on groundwater, indicates otherwise. She testified that witness Junis "tried to explain that it wasn't a flaw because groundwater is constantly moving, and therefore … every exceedance is a new example of where the groundwater has moved and contaminated … additional clean groundwater." (Tr. vol. 27, 277.) But, she added "that actually isn't how groundwater behaves." (<u>Id.</u>) Rather, if the plume is stable, then these are not "new exceedances" (<u>id.</u>) – and the plumes at the DEC basins are, indeed, stable. As witness Wells stated, "[I]t's sitting, and it's stable, and our multiple models say it will continue to do so for hundreds of years, as we see it, if we take no further action." (<u>Id.</u> at 233-34.)

Simply counting exceedances is also "not a meaningful thing to do" (<u>Id.</u> at 277-78) because in the assessment phase of a groundwater investigation the number of “exceedances” will depend on the number of wells and the number of sampling events per well, which would be expected to increase as DEC and DEQ engage in the iterative process of delineating the plume. (Tr. vol. 24, 93.) As witness Wells, indicates, as part of that process new wells have been installed, and the location of the compliance boundary has changed, such that some wells were reclassified as being located at or beyond a compliance boundary. (Tr. vol. 27, 63-64.) The number of exceedances today, given the extensive groundwater monitoring required in order to comply with CAMA and the CCR Rule, says nothing about any alleged mismanagement in the past. (Id. at 63.) To the contrary, DEC’s “comprehensive assessment demonstrates responsible actions that enable the Company and its regulators to better understand the impacted areas and drive appropriate corrective action.” (Id. 64-65.)

Second, the Public Staff completely ignores the fact that the 2L corrective action rules are “remedial”-oriented as opposed to “compliance”-oriented. (Tr. vol. 27, 166-67.) The distinction is crucial to an understanding of why a 2L exceedance or “violation” is not necessarily an indication of mismanagement. But this is a distinction apparently completely lost on the Public Staff. It was explained in detail by witness Williams:

> [The distinction] is important because the class of remedial requirements, including North Carolina’s 2L requirements, recognize that environmental contamination, including contamination that constitutes environmental harm, can result when an entity is in full compliance with all operational performance requirements. That is, a company may operate a facility in compliance with all waste and chemical management design and operating laws and regulations and still have releases to the environment that require either investigation or remediation under remedial laws.
>
> The practical reasons for this distinction are obvious. Operational performance requirements including specific permit conditions, while designed and intended to prevent environmental harm, are not fail-proof. These requirements may not adequately address all activities or all chemicals with the potential to result in environmental harm, in part because our understanding and knowledge regarding how to achieve protection is constantly evolving.

(Id., 168.)[21]

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[21] Exactly the same distinction was referenced by the Commission in the 2018 DEC Rate Order:

> Witness Wells also disagreed with the Public Staff’s suggestion that any exceedance or violation of water quality regulations, no matter how minor or how long ago, leads to the denial of cost recovery for any activity that acts to “cure” the impacts of the violation. In addition to reiterating that not all exceedances of the 2L standards amount to a violation that requires corrective action under the 2L rules, witness Wells stated that even when an exceedance requires corrective action, the

Third, just as with seeps, the Public Staff completely ignores the actual history of the 2L corrective action rules and their relationship to permitted facilities, like DEC's ash ponds, that predated the promulgation of those rules in 1984.[22] Pre-existing facilities were expressly addressed in connection with the establishment of corrective action requirements. (Tr. vol. 27, 19 (Witness Wells testified that the report accompanying the promulgation of the corrective action rules noted that "[I]t is probable that some violations do exist where facility construction predated the groundwater standards …[and that DEQ would address issues when] NPDES permits come up for renewal …").) And, indeed, groundwater monitoring requirements at a number of the ponds were addressed in the NPDES permitting process. (Id., 39.) Beginning in 2009, DEQ "began systematically adding groundwater requirements to NPDES permits as they were reissued or modified" (id.), and then "[a]s additional data became available and both the Company's and DEQ's understanding of groundwater impacts matured, [DEQ] issued a policy memo, dated June 17, 2011, titled 'The Policy for Compliance Evaluation of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirements.'" (Id., 39-40; see also Hart Ex. 12 (2011 DEQ Policy, or, simply, Policy).)

The 2011 DEQ Policy was described in detail by witness Wells. (Tr. vol. 27, 40.) As he indicated, the Policy included a detailed flow chart dictating the steps to be taken by the Department and the permittee (i.e., the utility) upon the identification of a groundwater exceedance near a coal ash pond, including (1) verifying the accuracy and significance of the results of the groundwater testing; (2) determining whether and to what extent the identified substance could be naturally occurring; and (3) evaluating other possible sources of the identified substance. After these steps had been completed, and after DEQ and the affected utility had determined that the exceedance was from an ash pond, the Policy required the parties to work together to develop a corrective action plan. Notably, the Policy itself indicates that enforcement action by DEQ – the issuance of a Notice of Violation, along with fines and penalties for non-compliance – would ordinarily be unnecessary unless the permittee was uncooperative through the process described in the flowchart. This underscores the "remedial" orientation of the 2L rules.

In this case, witness Wells testified that

> Impacts to groundwater around ash basins are not the result of mismanagement. The existence of groundwater exceedances at or beyond the compliance boundaries at these sites is a function of

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> groundwater rules do not treat the exceedance the same way as, for example, the Clean Water Act treats an exceedance of an NPDES permit limit. When the latter is violated, he explained, the permittee is immediately subject to an NOV and penalty, and must ensure the next discharge complies with the permit limit or risks a new NOV and escalating penalty. Tr. Vol. 24, pp. 244-45.

(2018 Order, at 298.)

[22] While the 2L rules themselves first came into being in 1979, their corrective action requirements were introduced in 1984.

> where these sites are on the timeline of groundwater assessment and corrective action under modern laws that have changed the way that unlined basins are viewed. As these views have changed, the Company has taken every action required by … [its environmental regulators] to address groundwater impacts as they have been identified.

(Tr. vol. 27, 56.) He testified in exactly the same way in the Company's prior case. (2018 Order, at 250-51.)

Just like with seeps, the Commission heard all of this evidence in the Company's prior case. (2018 DEC Rate Order, 298-99.) The Commission indicated that witness Wells "concluded that compliance with this process is not mismanagement and should not be held against DEC with respect to cost recovery." (Id., 299.) It expressly *agreed* with that conclusion. (Id.) Yet, the Commission is once again faced with regurgitated arguments from the Public Staff. It rejects them once again.

CCR Costs sought for recovery in this case were expended in order to comply with requirements of CAMA, including its 2016 amendment, and the CCR Rule. CAMA and the CCR Rule are very prescriptive, and require the Company to take specific steps spelled out in their text in order to be in compliance. The Company's coal ash basins are required to be closed under these requirements. Witness Junis asserts that "ultimate closure of all coal ash basins" will correct "environmental violations" (Tr. vol. 20, 406), but the only "violations" the Public Staff identifies are surface water discharge requirements (allegedly violated by seeps) and exceedances under the 2L rules. However, witness Junis fails to show any causal connection between the surface water discharge requirements or the exceedances and basin closure, because there is no causal connection. Indeed, there is no causal connection even to the groundwater treatment systems the Company has been required to install to meet the prescriptive requirements of CAMA/CCR Rule, pursuant to agreement with DEQ and memorialized in Special Orders on Consent. Had the Company been able to proceed under the 2L rules alone, natural attenuation of the groundwater plume would have been an option (Tr. vol. 28, 126), and a considerably less expensive one. Under CAMA/CCR Rule, as opposed to the 2L rules alone, and basin closure is required – not because of any mismanagement, but because of the mandates written in to CAMA and the CCR Rule by the General Assembly and EPA.

The dissent in the 2018 DEP Rate Order[23] (E-2, Sub 1142) recognized the lack of any causal connection as well:

> Had the Company's management of coal combustion wastes resulted in no exceedances of the state's 2L groundwater standards, no violations of any NPDES permits, no criminal prosecutions, and

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[23] Order Accepting Stipulation, Deciding Contested Issues and Granting Partial Rate Increase, Docket No. E-2, Sub 1142 (Feb. 23, 2018).

> no civil or administrative lawsuits, the record taken as a whole shows that the Company would eventually have been required to undertake many or even most of the ash disposal activities now required of it by the CCR Rule and CAMA.

(*See* 2018 DEP Rate Order, Commissioner Clodfelter concurring in part and dissenting in part, at 9.) The lack of a causal connection means that the Public Staff cannot show that any of the CCR Costs sought for recovery should be disallowed because of "environmental violations."

During her direct examination in the DEP-specific hearing witness Bednarcik was given a homework assignment – to determine whether it was possible to break out the costs of corrective action necessitated under CAMA and/or the CCR Rule for 2L rule exceedances beyond the compliance boundary. Witness Bednarcik did her homework and reported back when she was on the witness stand in the rebuttal phase of the hearings. The answer was that it was not possible – because what would have been required by DEQ in the absence of CAMA and the CCR Rule, and operating just under the 2L rules, is unknowable because DEQ has wide discretion, and the Company simply does not know what would have been required under 2L alone. (DEP Tr. vol 18, 49-50.)[24] She concluded "Where we sit today is we have to comply with CAMA and CCR" (id., 50) – the prescriptive rules and regulations that now govern what the Company must do and when it must do it. The Public Staff already knows this, and witness Junis' own testimony reflects that it knows this. He states that 2L rule costs "***cannot be quantified without undue speculation***." ((Tr. vol. 20, 406) (emphasis supplied).)

The questions for the Commission regarding the 2L rules are identical to the questions regarding seeps: (1) was there mismanagement, and, if so, (2) what economic consequences of that mismanagement are to be visited upon the Company. The answers once again are (1) No, and (2) Not Applicable – and even if (2) were applicable, once again no one, and certainly not the Public Staff, has calculated any economic consequence *to* be visited upon the Company.

Discussion of Question #2: Viewing the Company Historical Actions and Decisions Through the Prudence Framework

The prudence standard requires a detailed and fact intensive analysis into the challenged conduct. This analysis necessarily involves detailed inquiry into industry standards, inasmuch as conduct that conforms to the standards of the industry as a whole can hardly be deemed to be imprudent. The analysis also requires quantification of impact, inasmuch as cost disallowance requires quantification – without quantification there is no proven actual dollar amount the Commission may disallow. Under the prudence standard, the Company is entitled to recover the entirety of its CCR Costs. DEC has shown that its expenditures were reasonable and prudent.

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[24] At the Company's request and with the consent of all parties, the Commission has taken judicial notice of the evidence from the DEP-specific hearings referred to in this Order.

Here, the challenges mounted by the Public Staff, the AGO, and Sierra Club all fail under the prudence standard. First, DEC has shown that its historical coal ash management practices met or even exceeded industry standards. Further, while no Intervenor has shown such historical imprudence, even if there were any, no Intervenor has been able to quantify the impact of such conduct upon and in relation to the CCR Costs actually incurred by the Company in the January 1, 2018 through January 31, 2020 period – a period long after any alleged (but still unproven) imprudence could have occurred.

Without quantification, Intervenors' challenges fail. Public Staff's theory openly concedes an absence of any quantification and seeks only to allocate a disallowance premised upon a theory of "equitable sharing." Similarly, Sierra Club has not attempted to quantify the impacts of the Company's past activities, nor can they. The AGO attempted to "quantify" the disallowance through the testimony of its witness Steven Hart, who advocated multimillion-dollar disallowances through what he termed his "time value of money" quantification method. His methodology, which enjoys no support whatsoever from any peer reviewed authority – or any authority at all – fails to quantify any impact of supposed imprudence upon customers, because it merely shows at various earlier points in time costs equivalent to current CCR Costs, meaning that the "difference" in cost under his methodology is actually zero. (Tr. vol. 22, 168.)

Nevertheless, viewing the evidentiary record through the lens of the prudence framework, including industry standards – as the Commission must do, as there is no other lens through which to view it – answers the cost recovery issues presented in this case just like it answered them in the Company's prior rate case. This goes well beyond Intervenors' failure to quantify costs, although that failure alone would justify rejection of their disallowance claims. In addition to Intervenors' failure to quantify, DEC is entitled to recover CCR Costs in this case because it has proven that it acted reasonably and prudently throughout the pre-CAMA/CCR Rule period upon which Intervenors center their "fault" based attack on the Company's conduct.

In addition, the Commission cannot lose sight of the fact that it has heard all of this before, and already decided these issues. In the 2018 Order the Commission held:

> The limitations of the Intervenors' and the Public Staff's approach is the fact that the kinds of actions they appear to have favored – such as lining ash ponds when others in the industry were not lining them, or creating dry ash basins when the Company's industry peers were sluicing coal ash into wet basin impoundments, would (a) have increased costs that would have been charged to customers, or (b) would have left the Company open to credible claims of "gold-plating," and therefore cost disallowance, which would have prevented the Company from moving forward with these suggested improvements in the first place. These parties advance inconsistent positions. They fault the Company for not undertaking steps that others were not, but at the same time disavow any responsibility of

> paying for that which they – in 20/20 hindsight – wish the Company had undertaken.

(2018 DEC Rate Order, at 301.) The Commission was therefore "not persuaded … that any past violations by DEC, or many of its past coal ash management practices, support the discrete amounts of cost disallowances advocated by the Intervenors and the Public Staff in this case." (Id., at 302.) Nothing Intervenors have submitted in this case moves the needle from the manner in which these same issues were decided in the last case.

1. Industry Standards – Unlined Ash Ponds

Industry standards are the touchstone for prudence. As we have seen (see pp., above), prudence is an attribute of "Good Utility Practice" (Lesser & Giacchino, at 40), and "Good Utility Practice" includes "the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period" (Id. at 40.) That is, Good Utility Practice – prudence – is judged in relation to the utility's conformance with industry standards. DEC's continued operation of unlined basins until the change in law wrought by CAMA and the CCR Rule was compliant with industry standards. The Company proved this through the testimony of witness Williams, among others:

> [I]n evaluating whether a company operated reasonably it is certainly appropriate to compare that company to others in the same or similar industries. … EPA's 1988 CCR Report to Congress found that of the 483 CCR surface impoundments in the United States less than 10% (45) were found to be lined and of the 195 surface impoundments in the Southeastern United States (EPA's Region 4), less than 2% (3) were found to be lined

(Tr. vol. 27, 73.) Witness Williams' observation is further buttressed by the testimony of Rudolph Bonaparte, who demonstrated that the Company, consistent with its peer utilities in the Southeast, managed coal ash in unlined surface impoundments throughout the pre-CAMA/CCR Rule period. Witness Bonaparte's investigation was presented through a report (Geosyntech Report, Bonaparte Ex. 2) which found that over 90% of the CCR impoundments "were either directly reported or interpreted to be unlined" and that most of them were reported as being active in the timeframe of the investigation (2009-11). (Id., at 9.) The Company last constructed a basin in 1982, and of the seventy-four basins reported to be pre-1982 construction, only one had a liner, and that was due to site specific conditions (located in karst terrain). (Tr. vol. 24, 100.) Thus, essentially 100% of the pre-1982 basins in North Carolina, South Carolina, Georgia and Virginia were unlined. No Intervenor can say with a straight face that the Company deviated from the practices of the industry as a whole. Indeed, the AGO's coal ash witness in the last round of cases "testified that the majority of utilities continued to use unlined wet ash impoundments even after this timeframe, because '[t]he law allowed them to do it, and the law continued to allow them to do it.'" (2018 DEC Rate Order, at 267.) Witness Quarles in the previous cases testified to the same effect. (DEC Quarles Cross Examination Ex. 1, at 199 (utilities continued to use ash ponds because "it was convenient and there was no regulatory standard" prohibiting the practice").)

Accordingly, when Intervenors fault DEC for continuing CCR management in unlined ponds and not switching to dry ash handling earlier, they must contend with DEC's conformance with industry standards in continuing to operate the ponds – and they do not. This is in addition, of course, to Intervenors' complete inability to quantify the effects. As the Commission held in its recent Dominion Order, no party in that case presented evidence as to what CCR Costs, if any, "might have been avoided if DENC had used a different approach to managing its CCRs at some point during the last several decades." (2020 Dominion Rate Order, at 129.) The Commission observed further:

> For example, one could argue that DENC should have converted all of its coal-fired plants to dry ash handling at least at some time during the 1990s. However, to quantify the costs and benefits of this strategy would require establishing, with some level of certainty, the costs that DENC would have incurred for such conversions, and the savings in present CCR remediation costs that would have resulted from such conversions. In addition, DENC could have been entitled to recover those conversion costs, plus a return on its increased rate base, from its ratepayers over the past several decades.

Exactly the same considerations apply to DEC, and Intervenors were likewise unable to overcome these hurdles in their presentations in this case.

2. <u>Industry Standards – Groundwater Monitoring</u>

Intervenors contend that the Company engaged too late in "comprehensive" (Junis – Tr. vol. 20, 464) or "proactive" (Hart – Tr. vol. 16, 707) groundwater monitoring at its coal ash basins. They do not define these vague and nebulous terms. Once again, their claims founder upon the rock of industry standards.

Witness Williams – with "an almost 50-year career centered on environmental protection and regulation, spanning government service with the United States Environmental Protection Agency (EPA, or the Agency) (over 17 years), a senior management position in the waste management industry (approximately 3 years), and consulting work (almost 30 years) in which … [she has] been a consultant to both private industry and government agencies on a wide range of environmental matters" (Tr. vol. 27, 76) unequivocally testified that DEC was well ahead of its industry peers in initiating and conducting groundwater monitoring at its coal ash ponds. She summarized the evidence supporting her observation on the last day of the hearings:

> Well, again, the facts that I rely on for that are a lot of the national surveys that EPA did over time that talked about how many locations had groundwater monitoring. So I tried to go through some of them yesterday. I have a number of them in my testimony. But, for example, in the 1988 Report to Congress on coal ash EPA talked about it, but more importantly, EPA did a very broad and complete

> study of how many sites had groundwater monitoring in 1986 for all types of surface impoundments. And included in that were coal ash ponds, but it was much broader than just coal ash ponds. So I used those statistics, okay? And those statistics, again, consistently, from the '80s all the way through to the time frame when EPA was doing its proposed rule, you were seeing numbers like 33 -- 32 percent, 33 percent, 35 percent of these facilities had groundwater monitoring installed, and so I think it really is noteworthy that by the time you get to 2008, you know, when Duke had completed installing initial well systems at all of its facilities that hadn't already installed them due to a requirement in an NPDES permit, they installed it at the rest of the facilities by 2008.

(Tr. vol. 29, 41-42.) But she had testified repeatedly to the same effect the previous day. (See, e.g., Tr. vol. 27, 206, 283, 285.)

No witness in this proceeding had the depth of knowledge and expertise on the subject of groundwater regulation possessed and displayed by witness Williams. She stated, regarding DEC's groundwater monitoring program, "I believe in light … of the fact that [DEC] had installed groundwater monitoring systems before many of the industry had done it at all their facilities and were then improving them and working with them, I believe they did what you would reasonably expect a prudent utility to do." (Tr. vol. 29, 71.) Intervenors are unable to refute this expert observation.

EPA never required groundwater monitoring at any coal ash pond until it included a monitoring requirement in the CCR Rule – in 2015. (Tr. vol. 27, 285.) By then, DEC was already monitoring groundwater at every single one of its ash basins, and had been doing so for years – in coordination with its environmental regulator, DEQ. Working with DEQ is of course the prudent course. As the Commission noted in the prior case, "Determining the number and placement of monitoring wells, ***not an inexpensive endeavor***, is an inexact science." (2018 DEC Rate Order, at 264 (emphasis supplied) (citation omitted).) Not working with DEQ would have been imprudent – had the Company charged ahead and DEQ decided later that a different number of wells, or placement of them in different locations, would have been better, the Company would have incurred costs – potentially significant costs – and the Public Staff and other Intervenors would no doubt have objected to those costs being passed along to customers.

The picture Intervenors paint is of an environmental regulatory agency – DEQ – that was disengaged and a regulated entity – DEC – that was passive. Neither part of the picture is true. The undisputed evidence indicates that Colleen Sullins, who began her career at the Division of Water Quality within DEQ in 1992 writing permits for large industrial users and ended up being the Director of the Division of Water Quality in 2007 before retiring in 2011, testified that "Coal ash has been an issue that I dealt with for most of my career at the Division of Water Quality." (DEC Hart Cross Examination Ex. 4, at 22.) And the reason is obvious:

> [T]he power companies [meaning DEC and DEP], we were constantly in interaction with them because we were issuing permits for them to do a variety of different things.
>
> So you know, they were sort of always on the radar like a large, a large permitted entity would be and a complex permitted entity because it involved multiple divisions trying to figure out how to issue the various permits for which they had responsibility and deal with the various issues.

(Id., at 30.) Every single one of DEC's coal ash basins was permitted by DEQ, and those permits constantly came up for renewal on a periodic cycle. To portray DEQ as disengaged is to twist the facts into an unrecognizable shape, far removed from reality.

The notion that DEC was a passive bystander waiting for DEQ to tell it what to do also twists the facts into something far removed from reality. The Company began groundwater monitoring at the Allen Plant in 1978, in partnership with EPA. (Tr. vol. 27, 37.) The purpose of the investigation was "to evaluate the performance of Duke's ash basins, and their effect on groundwater movement and water quality" across its system." (Id.) DEC initiated the investigation voluntarily – there was no EPA or DEQ directive to do so – because of the suggestion at the time by regulators and industry of "a potential for groundwater impact." (Id., 234.) This is the very issue Intervenors identify (see Tr. vol. 16, 705 (Hart: utility industry, including DEC, knew of "potential" for groundwater contamination as early as the 1980s); Tr. vol. 18, 35-36 (Quarles); Tr. vol. 20, 437-39 (Junis).) But, contrary to the portrayal by Intervenors, DEC did not sit on its hands, it proactively and voluntarily investigated this "potential."

The Allen Plant was also selected for study by the EPA, conducted through a contractor, Arthur D. Little, Inc., inasmuch as EPA viewed it as representative of sites located in the Piedmont region. (Id., 37-38.) The Company conducted leachate studies for the purpose of assisting regulators in developing future groundwater standards that could be used at the regional or state level. (Id., 37.)

Both studies – DEC's internal work, performed on a voluntary basis, and Arthur D. Little's work performed on behalf of EPA – concluded that the wet sluicing of coal ash to Piedmont region ponds did not have a significant impact to groundwater: "And the key conclusion, not just from Duke's internal voluntary work … [but also the] A. D. Little work, was the same. And that is the impacts were localized, they weren't seeing a risk, they weren't seeing a significant impact." (Id., 236.)

It is against this backdrop that witness Junis indicates that DEC should have installed a "robust" (another undefined standard) system of wells in the early 1980s. (Tr. vol. 20, 451.) To the contrary, the results of the 1980s studies did not indicate the need for additional monitoring (Tr. vol. 27, 236), and the ultimate conclusion of EPA's 1988 Report to Congress was that there was no need to change then-current coal ash waste management practices, inasmuch as those practices "appear[ed] adequate for protecting human health and the environment." (Joint Ex. 13 at 7-11.) Spending money in the 1980s on a "robust" (whatever that means) system of wells at DEC coal ash basins, in the face of the Company's own conclusion that no significant impact from the basins existed, in the face of EPA/Arthur D. Little's identical conclusion, and in the face of EPA's conclusion that existing coal ash management techniques were adequate would indeed have opened the Company to "to credible claims of 'gold-plating,' and therefore cost disallowance (2018 DEC Rate Order, at 301) – and the Public Staff and AGO would no doubt have led the charge.

3. Industry Standards – Terminal Net Salvage and Cost of Removal

The AGO appears to be advocating disallowance at some (unspecified) level pursuant to a theory that the Company was at fault for not including in prior rate cases the terminal net salvage cost of its ash ponds in depreciation expense. In other words, the AGO's theory apparently is that the Company *undercharged* its customers at some undefined earlier point(s) in time by failing to include the "cost of removal"[25] for ash ponds in depreciation expense, and, therefore, rates. Putting aside whether supposedly undercharging customers in past rate cases is even a viable theory to justify a disallowance in a pending rate case,[26] the AGO does not factor into the equation whether the Public Staff would have supported inclusion of ash pond cost of removal in rates,[27] or whether the Commission would have, at this undefined earlier point in time, approved rates including cost of removal. Prepayment of costs that may not be tapped by the utility for many years is, understandably, highly controversial. (See Tr. vol. 22, 204 ("[H]istorically, utilities have faced resistance – at times strong resistance – to" inclusion of cost of removal in rates, both as to the concept at all and as to estimation of the future costs).) Apparently, these hurdles are of no moment to the AGO.

The AGO submitted no evidence to support any "cost of removal" disallowance, and for that reason alone the Commission may disregard the theory. (See 2018 DEC Rate Order, at 260.) But under the prudence framework, the AGO's argument fails in any event, because DEC's actions in connection with cost of removal were in conformance with industry standards.

The testimony regarding such conformance comes from Company witness John Spanos, and specifically in his pre-filed rebuttal. Alluding to a data response submitted to the Public Staff (DR 158), witness Spanos indicated that prior to the mid-2010s, with the

[25] "Cost of Removal" is a regulatory mechanism to allow for recovery of retirements in advance of their occurrence. (Tr. vol. 24, 16.) In effect customers prepay retirement costs through building a reserve. (Id., 16-17.)

[26] The rates in each of the Company's past rate cases were approved by the Commission and are, therefore, "just and reasonable" by definition. N.C. Gen. Stat. § 62-132.

[27] In this Docket, for example, the Public Staff opposes reflecting the accelerated recovery of remaining depreciation expense due to planned early retirement of several of the Company's remaining coal-fired plants.

passage of the CCR Rule,[28] that "it was not standard industry practice to include anticipated costs of coal ash impoundment closure in net salvage portion of depreciation expense," and he proceeded to note the reasons for this (Tr. vol. 22, 209-10):

- First, it was "not common" for decommissioning studies, which are used to propose depreciation rates, to include coal burning facilities because they were presumed to continue operating well into the future.[29]

- Second, ash basins would continue to be used to hold ash, and would continue to be managed and permitted.

- Third, "[w]ithout a definite plan to decommission these plants, or the specific manner at which the facility will be decommissioned, it was not appropriate to include decommissioning costs related to coal ash basin closures in the calculation of depreciation rates."

- Fourth, pre-CCR Rule coal ash basin closures ordinarily were planned and carried out in conjunction with the relevant environmental authorities, and prior to CAMA and the CCR Rule, "there was no clarity from federal or North Carolina environmental authorities as to how closure would be accomplished, rendering any cost estimations speculative."

- Fifth, and finally, following the enactment of CAMA and promulgation of the CCR Rule, which were the triggering events for the establishment of coal ash basin closure AROs, the applicable accounting rules shifted to ARO accounting rather than Cost of Removal accounting.

In addition, witness Spanos' pre-filed rebuttal testimony also recounted from his own personal experience discussions with and within the Company regarding the inclusion of basin closure costs in cost of removal, discussions that were also referenced in the Company's response to DR 158. (Tr. vol. 22, 211-12.) He alluded to a discussion in the Fall of 2011, in connection with preparation for a depreciation study dated as of December 31, 2011, which was ultimately used in the Company rate case filed in 2013 (Docket No. E-7, Sub 1026).[30]

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[28] Witness Riley likewise testified that ash basin retirement issues were *not* taken into account significantly in advance of the CCR Rule, but rather "as a result of" the CCR Rule. (Tr. vol. 24, 25-26.)

[29] Witness Spanos indicated that "In the case of the Company, it was not until the early 2010s that closure and retirement of coal-fired plants became a reality, due to the combination of tighter environmental regulation coupled with the falling price of natural gas." (Tr. vol. 22, 210.)

[30] This case is apparently one of the earlier rate cases in which the AGO asserts that the Company should have proposed an increase in depreciation expense so as to account for cost of removal of ash basins. As witness Spanos indicates, at the time of the discussions, "[I]t was anticipated that the Company would file a rate case in 2012. Ultimately this did not happen. It is my understanding that the filing was delayed by the July 2, 2012 merger of Duke Energy Corporation and Progress Energy, Inc. Shortly after the merger, the operating utility now known as Duke Energy Progress, LLC ("DEP," then known as Progress

The discussions included reference to a PowerPoint presentation dated October 18, 2011, produced in response to DR-158, a copy of which is included within Lucas-Maness Exhibit 1. The closure cost estimate presented in the PowerPoint was in excess of $1 billion. (Id., p. 7.) The presentation also indicated that the then-proposed CCR Rule was "not expected to be finalized until 2012 at the earliest." (Id.) Bearing all this in mind, witness Spanos testified that "The consensus we came to at the time was that these estimates were too speculative and would not support rigorous scrutiny from the Public Staff and/or the Commission." (Tr. vol. 22, 212.)[31] He continued, "Assuming the final Rule included a legal requirement to close coal ash basins, the Company advised that this new requirement would trigger the establishment of an Asset Retirement Obligation ("ARO") related to such closure." (Id.) In that event, ARO accounting would be followed, not cost of removal accounting.

This discussion shows that DEC, far from being oblivious to the possibility of seeking to capture cost of removal in depreciation expense actually considered it, but decided not to proceed because the costs were too speculative to withstand scrutiny and because it anticipated that a new legal obligation would soon be promulgated that would force the Company to shift in any event from a cost of removal/depreciation expense program to the spend/defer/recover program that the ARO structure would require. The notion that the Company was somehow at "fault" for not including cost of removal in depreciation expense under these circumstances is ludicrous.

Finally, witness Spanos referenced the fact that DEP did include decommissioning cost estimates for ash basins in depreciation expense in a rate case filed in 2012 (Docket No. E-2, Sub 1023), based on specific dismantlement studies prepared by a third-party consultant. He testified that

> Neither approach is "wrong"; rather, they were at the time both different but acceptable methods of calculating depreciation expense based on the information available and each company's judgment regarding the uncertainty of coal ash costs. The approach taken by DEC was simply more conservative than that of DEP.

(Tr. vol. 22, 213.)

The AGO elected not to ask witness Spanos *any* questions regarding this testimony at the evidentiary hearings. No one else asked any questions about it, either. It is entirely uncontradicted. Under the prudence framework, DEC's conformance with industry standards knocks out the AGO's theory.

Energy Carolinas, Inc.) filed a rate case (Docket No. E-2, Sub 1023), and the DEC rate case was filed in early 2013." (Tr. vol. 22, 211 fn. 29.)

[31] Only two years after the PowerPoint presentation the Company had further refined closure cost estimates, using the same closure assumptions, to slightly over $600 million. (See Docket No. e-7, Sub 1146, AGO Late-Filed Ex. 1-L, p. 35.) The prediction that the costs as estimated in the Fall of 2011 might be challenged as too speculative was certainly prescient.

4. Viable Alternatives – Early Ash Pond Closure

The prudence framework demands a comparison between viable alternatives; without that comparison, the Commission is not in a position to assess whether the alternative chosen was imprudent. In addition, quantification of effect cannot be ascertained without a comparison of alternatives, since the disallowance must be calculated as the difference between the (presumably) higher cost imprudent alternative and the (presumably) lower cost prudent alternative.

Intervenors posit that regulatory closure of ash basins at an earlier point in time (for example, in connection with the retirement of coal-fired units witness Spanos testified began occurring in the early 2010s) might have lessened current CCR Costs. Setting aside the fact that "might have lessened" is not quantification,[32] this notion also runs up against the "viable alternative" factor embedded in the prudence framework. In North Carolina, pre-CAMA and pre-CCR Rule, despite years of trying, the DEQ had simply not come up with closure rules, standards, and regulations.

The evidence of this is again completely undisputed, and was testified to at length by Company witness Jessica Bednarcik. (See DEP Tr. vol. 13, 61-63; Bednarcik Direct DEP Redirect Ex. 3 (Redirect Ex. 3) and Bednarcik Direct DEP Redirect Ex. 4 (Redirect Ex. 4).)

Redirect Ex. 3 is a memorandum memorializing a July 23, 2009 meeting between DEQ, DEP, and DEC regarding ash ponds. It starts out by indicating that DEQ had so far that year "received and responded to many questions from the media and the public about ash ponds," and that DEQ "staff had commended the utility companies for volunteering this groundwater monitoring program[33] and maintaining a productive working relationship with the agency." (Id., at 1.) The memorandum indicates that while DEQ had some pond closure requirements, they were "light on specifics" and that its two relevant subdivisions "would get together internally to discuss closure requirements for ash ponds." (Id., at 2.) It indicates further that DEQ did not state a timeframe by which it "would issue closure requirements for ash ponds." (Id.)

Redirect Ex. 4 is an email chain dated March/April 2013 between DEQ and "Duke Energy" (that is, after the merger of Duke and Progress, which occurred in July 2012). The email exchange reflects that in March 2013 DEQ sent Duke draft ash pond closure guidance developed "over the past year" and requested "feedback from our stakeholders,

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[32] The same factors that the Commission pointed to in the 2020 Dominion Order would also apply. To support a disallowance, the Commission would need evidence of savings resulting from early closure netted against the costs that would have been incurred in early closure, including cost recovery plus a return on DEC's increased rate base.

[33] Both DEC and DEP participated in a voluntary groundwater monitoring program at all of their ash pond sites, a program coordinated by the Utility Solid Waste Activities Group (USWAG) in partnership with the EPA "to implement a voluntary groundwater monitoring program to help federal and state regulators expand their knowledge of potential groundwater impacts from unlined ash basins." (See Tr. vol. 27, 44; Hart Ex. 13.)

Duke and the former Progress Energy, before going forward with this. (Redirect Ex. 4, at 1.) The requested feedback was provided in April. (Id.) Of course, this exchange took place almost four years after the DEQ had indicated, in Redirect Ex. 3, that it would come up with guidelines, although without any commitment as to a timeframe in which it would do so. As witness Bednarcik observed, this was not a "simple process" and it took "a long time … for DEQ to provide draft guidance." (DEP Tr. vol. 13, 63.)

The guidelines were never finalized. (Id., 64.) Instead, with the passage of CAMA and the promulgation of the CCR Rule, the General Assembly and EPA provided highly prescriptive rules for how and in what timeframe basin closure could and would proceed.

The prudence framework requires the Commission to compare alternative choices available to the Company if it is going to deem the chosen option to be imprudent. But in terms of early closure of ash ponds, closure at any time prior to CAMA/CCR Rule was not even an option, unless the Company wished to get ahead of its environmental regulator, and simply begin to close a pond without that regulator's buy-in. But that would have been imprudent – because without the buy-in, the Company had no assurance that its chosen path would have been approved by the environmental regulator. If not approved, then of course the Company would have been at risk of re-doing work – potentially very expensive work – it had already done. In that circumstance, it would have garnered no sympathy from the Public Staff, the AGO, or the Commission – its economic regulator.

Prematurely performing work, particularly in the timeframe after the publication by EPA of its proposed CCR Rule (Proposed Rule) in 2010 would have been even more fraught.[34] The scope of potential regulatory action set out in the Proposed Rule was very wide, so the issuance of the Proposed Rule increased, rather than decreased, regulatory uncertainty:

> The proposed rule offered regulatory options that varied significantly in how they would address existing ash ponds. One of the options would regulate CCR as a special waste under the hazardous Subtitle C regulations (the Subtitle C Option). Existing ash ponds would be required to meet similar requirements to hazardous waste surface impoundments or go through formal closure. Another option would establish standards for ash ponds under the non-hazardous Subtitle D regulations (the Subtitle D Option). Under this option existing ash ponds would also need to meet new technical standards, including composite liners, or close. However, EPA also offered a third option it called "D prime." This option was the same as the Subtitle D option, except that existing unlined ash ponds would not have to close or install composite liners but could continue to operate for their existing life. Therefore, the proposal left open whether existing ash ponds would be required to upgrade or close or could continue to operate

[34] This of course is the precise timeframe in which Intervenors, citing retirement of coal plants, indicate that basin closure should have occurred.

> as is and whether CCR would be regulated as a hazardous waste or as non-hazardous waste.

(Tr. vol. 27, 118.) Had EPA chosen the Subtitle C Option, the impact – in terms of what would have had to have been done and its cost – would have been "unbelievable" (Tr. vol. 28, 114); in contrast the D Prime Option would have meant the Company would "basically do nothing." (Id.) Guessing wrong could have led the Company to incur substantial costs and subjected to second-guessing by the Public Staff, the AGO, and the Commission.

The Commission addressed this very point in the Company's prior case:

> DEC in the past contemplated a future requirement to close unlined impoundments. While it was reasonable and appropriate to anticipate and plan for what EPA's ultimate decisions would be, the Commission determines not to penalize DEC through denial of cost recovery for its decision to wait until EPA's CCR determinations in this area were finalized. Had DEC acted prematurely in anticipation of regulations under consideration but not yet implemented, with the expenditure of substantial sums in the process, and with the ultimate EPA decisions differing from those anticipated, DEC risked unjustified expenditures.

(2018 DEC Rate Order, at 313.) The Commission even provided an example of how that might happen. It referenced EPA's 2015 promulgation of the Clean Power Plan, which imposed significant obligations upon the utility industry. The Commission noted that had "electric utilities incurred costs prematurely to comply, these costs could have been called into question when the U.S. Supreme Court stayed the Clean Power Plan." (Id.)

The danger of proceeding prematurely is also illustrated by Georgia Power's decommissioning of one of its coal-fired stations, Plant Arkwright. Closure also included the plant's coal ash ponds, which, like DEC's ponds, were unlined. The AGO introduced as a cross examination exhibit a 2004 manual published by the Electric Power Research Institute (EPRI) titled "Decommissioning Handbook for Coal-Fired Power Plants" (AGO Doss/Spanos Cross Exhibit 1 (2004 EPRI Manual)) which described the Plant Arkwright closure.

Ash pond closure at Arkwright was prompted not only by closure of the associated coal plant (something not contemplated for DEC plants until much later), but also by Georgia Power's desire to repurpose the plant site "for future development." (Id. at A-2.) Ash pond closure in Georgia had a defined regulatory structure, and the Georgia environmental authorities participated in the closure plan. (Id. at A-6.) Nothing similar was available to DEC in North Carolina.

But the Plant Arkwright pond closure serves as a cautionary tale, as its story was not finished in the mid-2000s. Despite the involvement of the Georgia environmental authorities in the closure, and despite the fact that Georgia had a defined regulatory structure for pond closure, Georgia Power is today having to re-do the closure, because the regulatory standards have changed from the time at which the work was originally performed. (DEP Tr. vol. 19, 707-08.) The notion that early closure would necessarily have resulted in lower (if still undefined) cost has no basis in objective evidence and is sheer speculation.

Company witness Williams, drawing on her decades of experience, testified that in light of all the regulatory uncertainties faced by owners and operators of coal ash ponds in North Carolina, it was prudent to wait "until after CAMA and the CCR Rule became law to take specific actions to upgrade or close ash ponds as long as they were working cooperatively with environmental officials to address any site-specific environmental issues." (Tr. vol. 27, 104-05.) No Intervenor witness has the credentials to credibly contradict this testimony, and no Intervenor witness did contradict this testimony.

DEC did intervene and work cooperatively with environmental officials to address site specific environmental issues. One example of this is the mid-1980s when DEC, working with DEQ, identified and corrected a high selenium issue affecting fish in Belews Lake. (See Joint Ex. 11.) Witness Wells testified, if the Company were to see a public health risk then "You move and take action. And that's what the Company has done throughout these years." (Tr. vol. 27, 229.) But for the most part, throughout those years, it did not see a risk. (Id., 230.) As he stated, the environmental studies and reports regarding the Allen Plant from "40 years ago" concluded that there was not then and not anticipated to be in the future a significant impact to groundwater. (Id., 233.) He found that conclusion to be reasonable looking at it from the standpoint of the time at which the studies were performed, but notes also that the conclusion is validated by today's science:

> And for what it's worth, even today that's the type data that we see, that attenuation. That concept of attenuation is there. …[O]ur plume today is just … sits there. As it moves, it attenuates, it's not a growing plume, … that plume is sitting beneath the basin and is extended outside the compliance boundary in certain areas … but it's sitting, and it's stable, and our multiple models say it will continue to do so for hundreds of years, as we see it, if we take no further action.
>
> But that's consistent with what was being discussed in those documents. So even 40 years later, much more sophisticated work, much more sophisticated modeling, still largely consistent with what they had found back then.

(Id., 233-34.) CAMA and the CCR Rule require highly prescriptive actions that the Company is compelled to take, and which it has taken. The notion that in the absence of those prescriptive requirements DEC should have taken those or similar actions earlier, and that doing so would have reduced cost, also has no basis in objective evidence and is sheer speculation.

5. Intervenors Operate in 20/20 Hindsight, which the Prudence Framework Prohibits

The prudence framework expressly forbids the Commission from evaluating a utility's conduct through the eyes of hindsight, which, of course is always 20/20: "Hindsight analysis – the judging of events based on subsequent developments — is not permitted."

(1988 DEP Rate Order at 14.) Unfortunately, however, Intervenors' testimony and arguments are infused with hindsight analysis.

Illustrating this point to perfection is the testimony of Public Staff witness Junis. He expressed his concern, in commenting on DEC witness Bednarcik's earlier testimony (Tr. vol. 15, 47), that in her review of some of the historical EPRI Manuals she tried to put herself in the timeframe of the documents (1981 and 1982) with the knowledge available at that time, and with that mindset concluded that she would not have done anything differently at the time. He stated in response:

> [Witness Bednarcik] stated very authoritatively that, based on reviewing all of this historical documentation, that if she was in a position to decide, she would have done nothing different in the management of coal ash over that period. ***I have great concerns about a scientist or engineer looking back over decades of time and not finding one thing that could have been done better or differently.***

((Tr. vol. 21, 78-79) (emphasis supplied).) This is witness Junis' philosophy – looking back, he could find all manner of things he would have done differently. But that in a nutshell is hindsight analysis. Witness Bednarcik, to the contrary, engaged in appropriate prudence review analysis – she sought to review decisions made in 1981 and 1982 "in light of the facts known at the time the decision was made" (Lesser & Giacchino, at 40), not looking at those decisions in 20/20 hindsight.

Further examples are witness Junis' overall criticism that the Company should have engaged in "comprehensive" groundwater monitoring earlier than it did (Tr. vol. 20, 440), and witness Quarles' criticism of the Allen Plant study (Joint Ex. 9) for "missing the perched water zone." (Tr. vol. 18, 46, 101, 121, 133.) DEC witness Williams took aim at both contentions, and showed that they were the product of hindsight analysis. (Tr. vol. 27, 213-14 (groundwater monitoring in the 1980s simply did not function the way it does today, and in in the Allen study timeframe EPA was itself still struggling with the perch zone and even as of 1986 had not come out with definitive guidance).)

Yet another example is witness Junis' criticism of the Company's Allen Plant study (Joint Ex. 9), which was conducted in the late 1970s and early 1980s. He stated in his review of the study he noted that the investigators had used prefiltered samples (Tr. vol. 21, 73), a practice prohibited by the CCR Rule and under North Carolina state rules. But it was not a practice prohibited in the late 1970s and early 1980s, as DEC witness Williams testified, noting that while "today there's definitive guidance on that, but in the 1980s there was not, and people were doing it all different ways." (Tr. vol. 27, 282.)

In witness Williams' pre-filed testimony she stated that the fact that DEQ "did not require [DEC] to modify the design of its ash ponds by requiring liners, did not require the ponds to close, or did not mandate groundwater monitoring earlier than they did, is a strong indication that [DEC's] operations were considered to be reasonable and protective by the Agency charged with protecting the North Carolina environment." (Id., 143-44.)

Challenged on this statement in cross-examination by counsel for the Public Staff, she testified that the statement was an "indication of what the knowledge base was at the time." (Id., 196.) She continued:

> [W]e've heard a lot of discussion here today about whether people are using today's knowledge to interpret what was going on back in many decades ago. You know, there's not a lot of advantages to being an old person, but the one advantage I can tell you is I lived through this. And so I can tell you that the level of knowledge and the level of thinking on groundwater, and the potential risks from groundwater contamination, and which types of facilities were understood to be the highest likelihood of causing issues in this exact time frame is extremely different than what everybody knows today. And that's a good thing, because we expect knowledge to improve, and it has improved on all kinds of topics.

(Id., 196-97.) Witness Williams was with EPA from 1970 through 1988. She knows exactly when Intervenor witnesses are employing hindsight analysis because she was there at the time and understands and knows from her own first-hand experience what was happening at the time.

Intervenors' inability or unwillingness to avoid hindsight analysis makes their testimony unreliable and untrustworthy. The Commission does not credit it, and disregards it when assessing the Company's conduct under the prudence framework.

Discussion of Question #3: The Company's Entitlement to a Return

DEC seeks a return, at its weighted average cost of capital (WACC),[35] on deferred CCR Costs during two distinct periods: the Deferral Period and the Amortization Period, both defined herein.

The Deferral Period is the period from the time the costs were first incurred through the date upon which they begin to be brought into rates. As it did in the Company's prior rate case, the Public Staff supports a WACC return in this period. (Tr. vol. 20, 494.) The Commission approved such a return in the Company's last rate case, in DEP's last rate case (Docket No. E-2, Sub 1142), and in Dominion's last rate case (Docket No. E-22, Sub 562). Thus, the Commission will not further address a return on CCR Costs during the Deferral Period herein; suffice it say that the reasons that a return is required during the Amortization Period apply equally to the Deferral Period.

[35] Company witness Sean Riley indicated that in the case of CCR-type costs, the "default" rate of return is the weighted average cost of capital (Tr. vol. 23, 176), which of course is necessarily true in order to compensate both debt and equity investors for the use of their capital.

The Amortization Period is the period over which deferred CCR Costs are amortized – that is, paid by customers over time – as they are brought into rates.[36] By definition, the CCR Costs to be recovered by the Company during the Amortization Period are prudently incurred – had they not been prudently incurred, the Commission would simply disallow them, and we would not then be facing any issue of a return "on" such disallowed costs.

The unamortized balance thus represents a loan by the Company to its customers. Under the spend/defer/recover model, prudently incurred CCR Costs were advanced by the Company to its customers, and are being paid back over time by its customers. Loans bear interest – the interest is the financing cost, the cost of the money borrowed. The return sought by DEC during the Amortization Period is synonymous with and equivalent to the cost of financing the unamortized balance of CCR Costs – the return is the cost of money. Responding to a Commission question, DEC witness Jane McManeus put it this way:

> [W]e use a number of terms when we're talking about this interest or return. Sometimes we call it the cost of money, sometimes we call it weighted average cost of capital, [sometimes] we say it's a debt and equity return, [but] it's [all] financing costs.

(Tr. vol. 15, 157.)

Were the Commission to deny DEC a return on the unamortized balance of CCR Costs during the Amortization Period, it would convert the loan made by the Company to its customers from an interest-bearing loan to an interest-free loan. Forcing the Company to make an interest-free loan to its customers under the circumstances of this case would be unlawful. The Commission recognized in the Company's last rate case that to deny DEC a return upon the unamortized balance would be unlawful. (2018 DEC Rate Order, at 290 (denying the return would impair the Company's ability to earn its authorized return and "[r]ates that impair the Company's ability to earn its authorized return are not just and reasonable … and the Commission would act contrary to law were it to order them.").) The facts and circumstances which led the Commission to that conclusion have not changed, and the conclusion still holds. But what is different today are the expectations created by that decision. These expectations lead to another reason for the Commission to award a return.

In the last round of rate cases for DEC and DEP, the Commission was writing on a blank slate. Coal ash cost recovery had not as yet been dealt with by the Commission in a fully litigated case. Both the prior DEC case and the prior DEP case were, however, fully litigated. In DEC's case, the Commission allowed full recovery of coal ash costs at issue, based on its finding that those costs had been prudently incurred. It further awarded

[36] The approved Amortization Period in the Company's last rate case was five years, and the Company proposes a like period in the current case. While it disagrees with the five-year period proposed, it agrees that amortization over some multi-year period is appropriate. (Tr. vol. 20, 489.)

full recovery (less a cost of service penalty) of a return on the unamortized balance of those costs as they were brought into rates during the Amortization Period. But the Commission went further. Rejecting an alternative cost recovery model (the "run rate") proposed by DEC, it held that "instead" DEC would be required to keep to its spend/defer/recover model of cost recovery, and that in the Company's next general rate case (which of course is this case) the Commission would undertake its prudence review of coal ash costs and "unless future imprudence is established, … [the Commission would] permit earning a full return on the unamortized balance." (2018 DEC Rate Order, at 322-23.)

The "spend" in spend/defer/recover represents funds advanced by the Company's investors. No investor advances funds without an expectation of a return. The promise embedded in the Commission's decision to require continued adherence by the Company to spend/defer/recover highlights even more that a Commission decision to deny the return in this case would be unlawful. Denial of an investment backed expectation is the foundation of a constitutional "takings" claim. (*Penn Cent. Transp. Co. v. New York City*, 438 U.S. 104 (1978).)

Simple fairness also must be factored into the equation. As witness McManeus testified, "[W]hen I think of what the Company's requesting, I think of it in terms of being made whole, and being made whole in terms of cost." (Tr. vol. 15, 158.) DEC cannot by definition be "made whole" if a significant cost – the cost of money – is disallowed in the same decision in which the underlying costs being financed are found to have been prudently incurred, and, therefore, are recovered – but recovered, as a rate mitigation measure to help customers, over time. Money is not free; to the contrary, it has a cost, as witness McManeus stated (Tr. vol. 11, 531; Tr. vol. 15, 89), and as no one disputes.

But fairness is not simply a matter of equity; it too is a legal requirement. Under N.C. Gen. Stat. § 62-133(a) rates set by the Commission must be fair to both the Company and its customers. Forcing the Company to make an interest-free loan to its customers can hardly be said to be "fair" to the Company. That is what also makes it illegal under N.C. Gen. Stat. § 62-133(a) and confiscatory under *Bluefield*/*Hope*. [37]

In the Company's last rate case the Commission noted that DEC and the Public Staff had engaged in a "strident" debate over whether a return on the unamortized balance during the Amortization Period "must" or merely "may" be approved, with the Company advocating "must" and the Public Staff advocating "may." (2018 DEC Rate Order at 275.) The Commission determined that it was unnecessary to decide this issue (Id.) Included in the debate was a further controversy between the Company and the Public Staff on the appropriateness and effect of the ARO accounting employed by DEC. The Company's testimony and argument showed that it appropriately accounted for CCR

[37] The interest-free nature of the loan means that the Company's ability to earn its authorized return would necessarily be impaired, and impairment of its ability to earn its authorized return constitutes an unconstitutional taking of property. *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*); *Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) (*Bluefield*).

Costs in AROs, and that pursuant to the ARO accounting rules those costs were capitalized and therefore should bear a return. The Public Staff took the position that the costs, even if accounted for in AROs, were deferred expense, and, therefore, a return was not required. Here, while indicating that the Company's position was correct and supported a return, and that the Public Staff's position was "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting" (id. at 289), the Commission again determined that this was an issue unnecessary to resolve. (Id.)

In the interest of not encouraging further re-litigation of these issues, the Commission resolves them here. The Company is legally entitled to a return, at its weighted average cost of capital during the Deferral Period, and is also legally entitled to a return, at its weighted average cost of capital, upon the unamortized balance of coal ash costs during as those costs are brought into rates during the Amortization Period. Those costs – the "spend" in spend/defer/recover – are "property used and useful" in the service of customers. Refusing to award the financing costs results automatically and as a matter of mathematics in impairment of the Company's earnings, which not only is prohibited by *Bluefield*/*Hope*, but in turn results in rates that are "unfair" to the Company in violation of N.C. Gen. Stat. § 62-133(a) and in violation of the Commission's mandate to set rates that are just and reasonable. Were it to refuse a return, the Commission would, in its own words, be acting "contrary to law." (2018 DEC Rate Order, at 290.)

A. Property Used and Useful

Under the Public Utilities Act, the Commission must provide the utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. *State ex rel. Utils. Comm'n v. General Telephone Co. of the Southeast*, 281 N.C. 318, 370 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. (Id.) These requirements are built into the rate-making statute, N.C. Gen. Stat. § 62-133. The rate of return deemed sufficient by the Commission to accomplish these ends is set in accordance with Section 62-133(b)(4), and the property to which the return is to be applied is measured in accordance with Section 62-133(b)(1). That Section states that the return is to be on "property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within the State."

The statute does not define the phrase "property used and useful." Intervenors appear to have a narrow view of its meaning, asserting that "used and useful" property is confined to utility plant assets that generate, transmit, and distribute electricity. The Commission has already decided that this narrow interpretation is incorrect (2018 DEC Rate Order, at 290-91), and, indeed, witness McManeus' testimony provides examples of non-utility plant assets that are nonetheless classified as property used and useful, such as reserve fuel and cash working capital. (Tr. vol. 11, 533.)

In *State ex rel. Utils. Comm'n v. Virginia Elec. & Power Co.*, 285 N.C. 398, 414-15 (1974) (*VEPCO*), the Supreme Court expressly recognized that when a utility keeps on hand a reasonable amount of shareholders' funds (in the form of cash) to pay operating expenses, such working capital constitutes property that is used and useful in providing retail electric service and should be included in rate base. The Court held:

> While Chapter 62 of the General Statutes makes no reference to working capital, as such, the utility's own funds reasonably invested in such materials and supplies and its cash funds reasonably so held for payment of operating expenses, as they become payable, fall within the meaning of the term "property used and useful in providing the service," as used in G.S. 62-133(b)(1), and are a proper addition to the rate base on which the utility must be permitted to earn a fair rate of return.

Id. Thus, to the extent that Intervenors continue to assert that "property used and useful" is limited to a utility's physical plant, that position is contrary to North Carolina law. Instead, under *VEPCO*, what stands as "property used and useful" does not turn on whether the property generates electricity, but whether it serves the public and was paid by debt or equity investors – rather than through rates that were set in anticipation of normal operating expenses.[38]

The CCR Costs DEC seeks to recover in this case were incurred as a result of the changes in law wrought by the CCR Rule (promulgated in 2015) and CAMA (initially enacted in 2014 and amended in 2016). On December 21, 2015, DEC and DEP submitted to the Commission and the Public Staff a letter (Savoy Letter, DEC Junis/Maness Cross Examination Ex. 4) that outlined the spend/defer/recover model DEC and DEP would follow in connection with their incurrence of the costs and the recovery of those costs in rates. The Commission in the 2018 Order noted that "through the Savoy Letter the Company told the Commission and the Public Staff, and the Commission told all interested parties" exactly how the program would work. (2018 Order, at 289.) No party objected to the Company's plan; indeed the Public Staff agrees that spend/defer/recover is the program in which the Company has been engaged, and that the program was outlined in the Savoy Letter and the subsequent formal deferral request submitted by DEC and DEP. (Tr. vol. 21, 41-42.)

To put CCR Costs into *VEPCO* terms, the "spend" in spend/defer/recover is "property" akin to the working capital that the Court held was properly counted as rate

[38] In the prior case, the Commission noted that it appeared that the Public Staff "misunderstood" the Company's position on what constitutes "property used and useful." (2018 Order, at 290.) In this case as in the last, the Public Staff misapprehends the Company's reliance upon *VEPCO* and its reference to working capital being a "property used and useful." (Tr. vol. 20, 512-14.) The Public Staff's regurgitation of the exact same "working capital" argument is yet another example of the Public Staff's willful blindness to the Company's actual – as opposed to imagined – positions.

base, upon which a return was statutorily required. It is cash supplied by investors, just like working capital is cash supplied by investors.

It is completely undisputed that the spent and deferred CCR Costs which DEC seeks recovery of in this case were advanced by the Company's investors, and are not included in current rates. DEC witness Jane McManeus so stated in her rebuttal testimony (Tr. vol. 11, 532), and reiterated it in response to a question from the Commission:

> [T]he way I think about it is, when we have amounts that we spend, for example, on coal ash, that are not yet reflected in our rates -- so, for example, the 2018, '19 spend is not reflected in our rates … by definition, investors [both debt and equity] are advancing these funds.
>
> … So when we say we want a return, we're talking about total financing costs on these amounts that have been advanced, and it's made up of both debt and equity.

(Tr. vol. 15, 157-58 (emphasis supplied).) No party submitted contradictory evidence, and Public Staff witness Michael Maness actually agreed. (See Tr. vol. 20, 514 ("The utility has already spent the money represented by the deferred costs in question; therefore, it will be required to borrow the money or use equity to finance the spent costs until it can recover them from ratepayers.").)

The "spend" in spend/defer/recover not only is "property" within the meaning of *VEPCO* and Section 62-133(b)(1), it is also provided in service to customers – the "spend" was made, and is continuing to be made, in order to comply with changes in the law; indeed, the Company does not have the option to *not* comply with changes in the law. (See 2018 DEC Rate Order, at 268-69 ("Capital expenditures undertaken to enable compliance with the law qualify as 'used and useful,' in that the Company does not have the option to fail to comply …".) Here, too, Intervenors have a narrow view of the meaning of the words of the statute. Witness Maness indicates that CCR Costs (which is what the "spend" constitutes) relate "to service that was provided in the past" (Tr. vol. 21, 131), and which are "not really providing any additional benefits to customers in terms of additional electric service or improvements of service." (Id. at 130.) But this makes no sense – the spend is occurring today as a result of changes in the law that came into being in 2014, 2015, and 2016.[39] But for the changes in law, there is no evidence whatsoever that the

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[39] In DEP's last case, the Commission rejected the Public Staff's "label-driven classification" of "used and useful" (2018 DEP Rate Order, at 195-96), noting as a "concrete example" that the "spend" in that case included new landfills with new liners, capital items with service lives of in excess of one year. (Id.) In DEC's current case, for example, its "spend" on a system basis through June 30, 2019 in connection with construction of the Buck beneficiation facility – a requirement of the 2016 CAMA amendments – was in almost $95 million. (Tr. vol. 13, 209.) This facility is essentially a manufacturing plant designed to convert coal ash from the Buck basins into a useable product in order to fulfill the reuse goals of CAMA as amended. The same considerations that drove the Commission in the 2018 DEP Rate Order to reject the Public Staff's "label-driven classification" apply with equal force in this case. Indeed, in light of examples such as the Buck

"spend" would be occurring at all. CAMA and the CCR Rule mandate basin closure – until they came into being, continued operation of the Company's ash ponds was entirely legal, and premature retirement could well have been imprudent and more expensive than the costs being incurred today. CAMA and the CCR Rule require the specific steps that the Company is taking to address and remediate groundwater contamination resulting from the normal operation of the basins. But for their prescriptive requirements, there is no evidence whatsoever that assessment and remediation of groundwater now being required would ever have been required under the law as it existed prior to CAMA and the CCR Rule.

In this case, Company witness Doss testified that the CCR Costs representing the "spend" funded by investors

> [A]re used and useful as those costs are reasonable and prudently incurred and are intended to provide utility service in the present or in the future through achieving their intended purpose: environmental compliance, the retirement of the ash impoundments and the final storage location for the residuals from the generation of electricity. The achievement of those three purposes is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule.

(Tr. vol. 22, 237-38.) Witness Doss provided identical testimony in the Company's prior case. (2018 Order, at 257.) In the prior case, the Commission credited his testimony, rejected the contrary testimony of witness Maness, who classified[40] the costs as "deferred expense" and therefore ineligible to even be counted as "used and useful," and found that the CCR costs that were the subject of the prior case were indeed "used and useful." (Id. at 292.) As the Commission held, quoting witness Doss, the achievement of CAMA/CCR Rule compliance and the other purposes of CCR spend "is used and useful as the utility has the obligation to comply with CAMA and the CCR Rule." (Id.)

Nothing has changed – the Company and the Public Staff extensively debated the appropriateness and effect of ARO accounting in the Company's prior case, and the same evidence was again submitted in this case, from witness Maness for the Public Staff, and witness Doss for DEC. The only "new" evidence came from Company witness Riley, but it served merely to buttress from a national perspective what witness Doss testified to from a Company-specific perspective.

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beneficiation project, witness Maness' general classification of CCR Costs as "deferred expenses" is no less label-driven, and, as it did in DEC's last case, the Commission rejects it.

[40] In truth ***mis***-classified, as the Commission found as a fact that his position was "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting." (Id. at 289.)

In the prior case, and after extensive discussion of applicable accounting standards under GAAP and FERC standards, along with the Commission's own deferral standards, the Commission ruled

> While the accounting rules detailed herein are complex, in simplified terms, both GAAP and FERC accounting guidance require the recognition of a liability (the ARO) upon the requisite triggering event – the legal obligation to retire the Company's coal ash basins. Recognition of the liability carries with it recognition of a corresponding asset – ***the capitalized cost of settling the liability, which under both GAAP and FERC rules is considered part of the property, plant and equipment for the assets that must be retired***.[41] While under ordinary circumstances these recognition events would be reflected over time in the Company's income statements, because of the deferral order in Docket No. E-7, Sub 723, the income statement impacts are deferred into regulatory assets "pending further orders of the Commission." The Company in this case is seeking such a further order, so as to reflect in rates the outflow of cash that it has incurred – and that its investors have funded – as it proceeds to settle the asset retirement obligation created by the CCR Rule and CAMA.

(2018 DEC Rate Order, at 288 (emphasis supplied).) This is what witness Doss testified to in the Company's prior case, and what witnesses Doss and Riley testified to all over again in this case. (Tr. vol. 23, 34 (Doss: Following GAAP and FERC guidance, very clear that CCR Costs accounted for in an ARO are capital costs); (Riley: Tr. vol. 23, 177-78 (FASB does not look at asset retirement cost as being a separate intangible asset; rather it "is part of the coal facility itself … part of that operating long-lived asset").)

Capitalized costs bear a return. The CCR costs incurred by DEC are capitalized costs, funded by the Company's investors, who advanced the funds expecting a return. In the Company's prior case, the Commission held that the deferred funds used to pay for the CCR costs at issue in that case

> [W]ere furnished by the Company and its investors, and the costs are eligible for a return on, not merely a return of, those funds, lest its earnings be impaired. In this sense, just like "classic" working capital, these funds are "property" of the Company, used and useful in the provision of electric service to its customers. Such funds, properly accounted for in an ARO, are eligible [for] "deferral and amortization and for earning on the unamortized balance."

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[41] This corresponding asset is the "Asset Retirement Cost," and is part of the long-lived asset (in the Company's case, the coal plants associated with the coal ash basins) whose required closure as a result of changed legal obligations created the liability – the ARO. (Tr. vol. 23, 162.)

(2018 DEC Rate Order, at 292.) The CCR Costs involved in this case are exactly the same. Nothing has changed, and the *VEPCO* decision and the Public Utilities Act mandate a return.

B. Deferral and Amortization Make a Return "On" Costs Imperative

In the 2018 Order, the Commission awarded a return on the unamortized balance of coal ash costs in light of specific circumstances tied to the spend/defer/recover model. The Commission first noted that coal ash costs had been advanced by investors – that is, the "spend" in spend/defer/recover was investor-supplied capital, and was not already included in customer rates. (Id. at 290-92.) The Commission noted further that the costs had been deferred by order of the Commission – that is, the "defer" in spend/defer/recover was Commission-sanctioned under the well-defined and long established rules governing deferral, in that CCR Costs were extraordinary in type and magnitude such that failure to defer would have a significant impact on the Company's earned returns. (Id. at 206-07, 292-93.) And, finally, the Commission noted that not awarding a return would impair the "recover" part of spend/defer/recover, because unless the investors who advanced the capital so as to permit the Company to "spend" received a return on the unamortized balance during the Amortization Period, the Company's ability to earn its authorized return would be impaired. (Id. at 290.) That, of course would mean that the investors would not be fully compensated for the use of their capital.

The Commission concluded "The funds used to pay for these costs were furnished by the Company and its investors and the costs are eligible for a return on, not merely a return of, those funds, lest its earnings be impaired." (Id. at 292.) While the Commission couched this conclusion in the language of "discretion," in reality the same factors it relied upon to award a return in the exercise of its discretion add up to the Company's legal entitlement to a return. That is because impairment of the Company's ability to earn its authorized return is, as the Commission already found in the 2018 Order, illegal. The reason for this is the deferral structure embedded in spend/defer/recover and approved by the Commission in the 2018 Order.

In DEC's last rate case, the Commission approved the deferral of CCR Costs currently being sought for recovery. (2018 DEC Rate Order, at 206-07.)[42]While that Order is currently on appeal, the deferral was not appealed. No party to the appeal argues in the appeal that deferral of ongoing coal ash costs is improper. Deferral has consequences, as the Commission held:

> The point of a deferral is that the costs to be deferred are of a magnitude that they need to be taken out of the normal ratemaking accounting process

[42] The Company has also requested authorization to continue deferral of its coal ash environmental compliance costs beginning February 1, 2020, as well as the depreciation and return on CCR compliances investments related to continued plant operations placed in service after January 31, 2020, along with a return on both the deferred balances at the overall rate of return approved in this case, for cost recovery consideration in a future rate case. Deferral is appropriate for the same reason that the Commission granted DEC permission to defer similar costs in the 2018 DEC Rate Order.

> and set to one side for later inclusion in rates, lest the Company lose its ability to recover them. Tr. Vol. 9, pp. 123-24. Should the Company's ability to recover such costs be impaired, it will not be able to earn at its authorized rate of return. *Id*. at 124. Setting them to one side means that unless a return is allowed, the Company's ability to earn its authorized rate of return is again impaired. Further, ***if in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return. Rates that impair the Company's ability to earn its authorized return are not just and reasonable … and the Commission would act contrary to law were it to order them.***

(2018 DEC Rate Order, at 290 (emphasis supplied).)

In this case the Commission has set an authorized rate of return (ROR) pursuant to N.C. Gen. Stat. § 62-133(b)(4). As witness Maness indicates, setting the authorized ROR in a rate case means that the Commission is "supposed to give … [the Company] the opportunity to recover just that cost of capital" coming out of the case. (Tr. vol. 7, 36.) But if it in that same rate case the Commission disallows a future cost – the cost of money as CCR Costs are brought into rates in the future, during the Amortization Period – the Commission would automatically and mathematically make it impossible for the Company to earn the ROR it had just authorized.

Company witness Sean Riley put the concept in more concrete terms. He noted first that if the Company is actually in an "out-of-pocket cash" situation[43] and it receives less than a full return then "that would be viewed as being a disallowance" (Tr. vol. 23, 174-75) – an "implicit" disallowance (Tr. Vol. 24, 37), but a disallowance nonetheless. Commissioner Hughes posed a hypothetical in which "$500 million was sought … and $500 million was granted, but over a period of time that caused a net present value disallowance." (Id. at 20). Witness Riley's response captures the impairment caused by the loss of the return in terms of the accounting for the loss, but it also illustrates the impairment of earnings implicit in the disallowance:

> [I]n your example, if the Company's seeking $500 million in recovery and they're granted $500 million in recovery, except if the Company is out-of-pocket cash today $500 million and they're not going to recover that for, say, a period of time, call it 25 years, they have used shareholder monies today, and shareholders expect a return on the use of their funds.
>
> So to the extent that the Commission were to only grant recovery over a 25-year period … in present value dollars it's something less than $500 million.

[43] The Company ***is***, of course, out-of-pocket cash in the spend/defer/recover scenario.

> And what the accounting would require is for the Company to assume or to assess what return would it have expected to get on those dollars, and I would have expected weighted average cost of capital. They would present value of those dollars back to today's dollars to today. Using your example, say that discounts back to $400 million. They would take a charge of $100 million for that implied disallowance in accordance with the accounting standard.
>
> So, in effect, because they're not getting a return on their money, that has to be recognized today as a charge.

(Id. at 20-21.) That same $100 million charge, or implicit disallowance, is – mathematically – an impairment upon the Company's ability to earn its authorized ROR. Amortizing the costs pre-funded by investors means that investors have in effect lent the money funding the costs to customers. Denying the financing costs attendant upon the loan being repaid over time impairs the Company's ability to earn its authorized ROR – an ROR authorized by the Commission in this very Order.

Impairing the Company's ability to earn its authorized ROR is illegal under *Bluefield*/*Hope*, the requirements of which are built into the rate-making statute through N.C. Gen. Stat. §§ 62-133(b)(1) and 62-133(b)(4). It is also illegal under N.C. Gen. Stat. §§ 62-133(a), which requires the Commission to set rates that are just and reasonable, and fair to the utility and its customers. A rate order that requires the Company to make a forced interest-free loan to its customers is not "fair" to DEC and its investors.

Further, sound economic principles underpin the award of a return on the unamortized balance as deferred costs are brought into rates over time. Barring extraordinary circumstances, operating expenses are paid through electricity rates, which are set at a level to cover those operating expenses based upon a test year which, as adjusted, is designed to mimic the electric utility's ongoing costs. When extraordinary expenditures arise that justify deferral, they are paid not through electricity rates set in anticipation of those costs but by funds advanced by the utility's debt and equity investors. In order to fully recover these expenditures, the financing cost attendant upon the advancement of the funds needs to be recovered – this is the return "on" those expenditures. Accordingly, the Company is entitled to a return at its weighted average cost of capital to be set in this case upon the unamortized balance of CCR Costs as those costs are brought into rates during the Amortization Period.

The Company's investors, who advanced the funds that are the "spend" in spend/defer/recover, would not have done so had they not had an expectation that their funds so invested would bear a return, and that return is the cost of the money – money they invested that allowed the Company to "spend" and incur legally required CCR Costs. Accordingly, the Commission should award a return at the Company's weighted average cost of capital to be set in this case upon the unamortized balance of CCR Costs as those costs are brought into rates during the Amortization Period.

Indeed, the 2018 DEC Rate Order created an investor expectation that a return "on" the unamortized balance of deferred CCR Costs would be awarded in future rate cases – in particular, *this* rate case – so long as the Company met its obligation to prove that the costs for which it sought recovery were prudently incurred. The creation of this expectation is another reason why the return sought by DEC is warranted.

C. The Expectations Generated by the Commission's Prior Order

In DEC's prior case, the Commission found that the CCR Costs incurred by the Company had been prudently incurred, and it allowed full recovery of those costs as well as a return on those costs, less a cost of service penalty. DEC had also sought recovery of then-future CCR Costs – which include of course costs *now* sought for recovery – through a "run rate" pursuant to which customers, not the Company's investors, would fund a significant portion of (if not the bulk of) ongoing CCR Costs. The Commission rejected the "run rate" concept, and held:

> ***Instead***, CCR remediation costs incurred by DEC during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). ***The Commission will address the appropriate amortization period in DEC's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance.***

(2018 DEC Rate Order, at 322-23 (emphasis supplied).) Thus, the Commission did not merely *endorse* the spend/defer/recover model in which the Company was engaged, and had been engaged since the laws regarding coal ash management changed with the passage of CAMA and the promulgation of the CCR Rule – the Commission *required* spend/defer/recover. (See Tr. vol. 4, 20 (Commission in not granting run rate forced Company to spend and defer the costs, but indicated that in so doing it would incorporate into rates the financing costs associated with that effort).) Further, the Commission's ruling "puts the focus of the Company's cost recovery request where it belongs – on the Commission's examination of the prudence and reasonableness of the costs for which the Company seeks recovery …." (Tr. vol. 11, 536.) That is, the ruling puts the focus on execution risk, which the Company and its investors properly assume, and not on the risk of an inappropriate disallowance of cost, which the Company and its investors do not and did not assume.

The Company's "next general rate case" is this case. DEC has done what the Commission asked. It booked its ongoing CCR expenditures – deferred by order of the Commission and funded entirely by investors – to an ARO. It has borne the burden of proving that its CCR expenditures were prudently incurred, so "future imprudence" as to the CCR Costs which it seeks to recover has *not* been established. A return during the Deferral Period is not opposed by the Public Staff. All that remains is for the Commission to uphold and fulfill the expectation that it created – the expectation that a return "on" CCR Costs would be awarded during the Amortization Period. Dashing investment backed expectation is a recipe for a "takings" claim (see *Penn Cent. Transp. Co. v. New York City*, 438 U.S. 104 (1978)). It is also a recipe for the abrogation in North Carolina of the regulatory compact. The Commission is not interested in abrogating the regulatory compact in North Carolina

The underlying predicate with respect to the costs to be brought into rates over time during the Amortization Period is that the costs were prudently incurred – because if they were not prudently incurred, the Commission would simply disallow them and there would be no question of a return "on" the disallowed costs. Investors accept the risk of prudence-based cost disallowance. That is "execution" risk – the Company must execute in order to recover its costs. But denying a return "on" prudently incurred costs goes well beyond execution risk. Rather, it strikes at the heart of the regulatory compact.

In the 2018 DEC Rate Order the Commission explained in detail the regulatory compact:

> A central operating principle underlying utility rate regulation in North Carolina (and virtually all other jurisdictions) is that the utility's costs are recoverable in rates. As two of the leading modern commentators on utility regulation put it …
>
> > No firm can operate as a charity and withstand the rigors of the marketplace. To survive, any firm must take in sufficient revenues from customers to pay its bills and provide its investors with a reasonable expectation of profit …. Regulated firms are no exception. They face the same constraints ….
> >
> > A basic concept underlying all forms of economic regulation is that a regulated firm must have the opportunity to recover its costs. … Without the opportunity to recover all of its costs and earn a reasonable return, no regulated private company can attract the capital necessary to operate.

(2018 Order, at 257 (quoting from Lesser & Giacchino, at 39).) Inducing investment carries a cost, too – the cost of money. Justice Brandeis, in his dissenting opinion in which he articulated the prudence principle, articulated as well that the capital cost, the cost of money, is a "cost" to the utility no less than "operating expenses, depreciation, and taxes." *Missouri ex rel. Southwestern Bell Tel. Co. v. Pub. Serv. Comm'n,* 262 U.S. 276, 306 (1923) (Brandeis, J, concurring and dissenting). This Commission has emphatically and repeatedly reaffirmed this principle.[44]

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[44] *See, e.g.,* Order on Remand, Docket No. E-7, Sub 989 (Oct. 23, 2013), at 22; Order Granting General Rate Increase, Docket No. E-7, Sub 1026 (Sept. 24, 2013), at 23.

To refuse a return in the circumstances of this case is to disallow financing cost – in effect, as we have seen, to force the Company to provide an interest-free loan to its customers. This has consequences. As DEC witnesses Karl Newlin and Steven Fetter noted, investors vote with their wallets. (Tr. vol. 1, 57 (Newlin); Tr. vol. 26, 135 (Fetter).) They have investment alternatives, and will go elsewhere if their return expectations are not met. Regarding recovery of CCR costs, and all other things being equal, investors "would prefer to go to a jurisdiction that would provide a return of and on as opposed to one … [that] provided just a return of, or even cut back the return of with no return." (Tr. vol. 26, 138.) The evidence in this case shows that other jurisdictions, including Virginia, Georgia, Florida, and Indiana, provide for both recovery "of" and return "on" coal ash costs. (Tr. vol. 3, 56; Tr. vol. 4, 37; Tr. vol. 26, 79-80, 138.) DEC witness Sean Riley answered "No" to Commissioner McKissick's question regarding whether other jurisdictions were "wrestling with" the coal ash issues (Tr. vol. 23, 180) – "No" because other jurisdictions were allowing "recovery of ***and on***" CCR costs, without disallowance. (Tr. vol. 24, 14 (emphasis supplied).)

The consequence of calling into question North Carolina's continued adherence to the regulatory compact is higher cost of capital, leading inexorably "to increased rates to North Carolina customers." (Tr. vol. 24, 15-16.) As witness Fetter noted, there are "another 180 utilities [investors] could invest in across the country outside North Carolina." (Tr. vol. 26, 148.) That is not an outcome the Company desires, and it surely is not an outcome the Commission desires.

This is not a theoretical issue – the credit rating agencies have already signaled the negative consequences were the Commission to adopt in this case the "no return" treatment it adopted in the Dominion case. Each Moody's credit report issued after the 2020 Dominion Rate Order was published contains the same warning – stable ratings outlook[45] is at risk if return on the deferred balance is disallowed. (See Tr. vol. 2, 51-55; Newlin Duke Redirect Ex. 3, at 3; Newlin Duke Redirect Ex. 4, at 4.) The last Moody's report for the Company itself pre-dated the Dominion Order, but contains its own stark warnings. Topping the list of "Factors that Could Lead to a Downgrade" is a decline of credit supportiveness in the Carolinas, "particularly with regards to coal ash remediation recovery in North Carolina" (Newlin Duke Redirect Ex. 2, at 2), and the report also reiterated that the ability to earn a return on the deferred coal ash balance was the underpinning for the Company's continued stable outlook. (Id. at 3.)

The non-theoretical nature of the threat was captured by DEC witness Steve Young, the Chief Financial Officer of Duke Energy Corporation. Noting that the Company's current credit ratings were "solid," he indicated that "where it's headed" was his worry (Tr. vol. 3, 52), and central to that worry is the concern expressed by investors, "whether it's debt or equity … [are you] going to get recovery of your cost, including debt service, including the ability to pay a dividend." (Id.)

[45] "Stable outlook means that the rating agency doesn't intend … to take a ratings action on the Company." (Tr. vol. 2, 49.) A shift to negative outlook would be "a precursor to a downgrade." (Id.)

Witness Young's testimony establishes that it is the strength of the Company's credit ratings and balance sheet that allows the Company to ride out crises such as COVID-19 (Tr. vol. 3, 55), or shoulder the burdens of hurricane recovery (id. at 53), or successfully navigate the risks of operating nuclear power plants. (Id.) The strength of the balance sheet and DEC's current A-level rating allows it the flexibility to access short-term capital through the commercial paper market, and then go into the longer term debt markets at a time of its choosing, rather than be forced to pay what the market demands at a non-optimal time. (Id. at 54.) This flexibility is what allows the Company to keep capital costs low, but underpinning this flexibility is the "confidence of the lenders that we'll be able to recover all the cost" (id.), which of course includes financing cost. The flexibility goes away if investor confidence goes away – to the ultimate detriment of customers, who must bear the higher cost of capital in rates.

Investors follow and rely upon the Commission's rulings, decisions, and pronouncements. In the Company's prior Order, investors saw that the Commission decided to award DEC a return on the unamortized balance of deferred coal ash costs during the Amortization Period. Without any change in the underlying circumstances, investors will be hard pressed to understand a change in outcome, particularly when the Commission's own words promised no change in outcome.

The cost recovery concern expressed by investors and overhanging the Company's credit and equity profile is not an issue to be addressed by superficial arguments such as "the approval of credit ratings agencies is not a requirement on the Commission in setting rates" (Tr. vol. 3, 41), or that "nowhere in … [N.C. Gen. Stat. § 62-133] does it say that rates have to be set to avoid a downgrade … or increase the stock price of utilities" (Tr. vol. 26, 107), or that Moody's or investors do not dictate the requirements of North Carolina law. These are strawman arguments. No one – least of all the Company – argues that Moody's or investors dictate the requirements of North Carolina law. Cost recovery in North Carolina is governed by the Public Utilities Act, decisions of the North Carolina appellate courts, and decisions of this Commission as it seeks to fulfill its legislative mandate to set just and reasonable rates, rates which must be "fair [both] to the … utility and to the consumer." N.C. Gen. Stat. § 62-133(a).

The proper response to the strawman argument is simple. The law does not prohibit the return; to the contrary a return is required, not because Moody's or investors seek to dictate this result, but because the Constitution and North Carolina law demand this result.

There is no provision of the Public Utilities Act, no decision of the North Carolina appellate courts, and no decision of this Commission that compels the Commission to force investors to bear the financing cost of prudently incurred CCR expenditures as those expenditures are brought into rates over the Amortization Period. This is particularly true when the costs are being amortized as a rate mitigation measure. There would not be financing costs at all were 100% of prudently incurred CCR Costs to be included in rates on Day 1. Customers get the benefit of being able to spread the introduction of CCR Costs into rates over time – but the corresponding burden is that they should also shoulder the cost of money that is attendant upon recovery of CCR costs being spread out over time.

The role of the Commission itself in the legal framework of cost recovery cannot be underestimated. The key to the spend/defer/recover framework is the deferral – but for the deferral, we would not be here today arguing about CCR cost recovery, or a return on such recovery, because without the deferral the costs would already have been written off and expensed. (Tr. vol. 23, 59-60.) Deferral is an integral part of the regulatory model (id. at 76), and deferral is a construct of the Commission. It is as much a part of North Carolina's legal landscape as the prudence framework or the concept of "used and useful" costs in rate base.

This brings us full circle to the deferral – which no party challenges – and the consequences thereof. As stated above, in DEC's prior case the Commission held:

> [I]f in the process of bringing the deferred costs into rates the costs are amortized over a period of years, not allowing a return on the unamortized costs again impairs the Company's ability to earn at its authorized rate of return. Rates that impair the Company's ability to earn its authorized return are not just and reasonable … and the Commission would act contrary to law were it to order them.

(2018 DEC Rate Order, at 290.)

Nothing has changed since the Commission wrote those words in 2018. Those words provide the rationale for recovery by DEC of a return "on" prudently incurred CCR Costs as those costs are brought into rates over time during the Amortization Period. Impairing the Company's ability to be "made whole" (Tr. vol. 15, 158) by disallowing its financing cost during the Amortization Period would be unconstitutional under *Bluefield*/*Hope*, and will lead to rates that are unjust, unreasonable, and unfair to the Company, while the Commission's mandate is to set rates that are just, reasonable, and fair to the Company.

Under the circumstances of this case, and in order to be made whole, DEC is entitled to a return at its weighted average cost of capital on the unamortized balance of CCR Costs as those costs are brought into rates during the Amortization Period.

D. Additional Public Staff Arguments Against a Return

The principal reason the Public Staff removes CCR Costs from rate base so as to deny the Company a return on the unamortized balance of those costs during the Amortization Period is to implement its 50/50 "equitable sharing" theory, a theory that is standard-less and arbitrary. But protection of its chosen sharing percentage is not the only reason that the Public Staff would deny a return on the unamortized balance. It also makes a legal argument based upon its classification of CCR Costs as "deferred expenses," noting that expenses are not "property used and useful under 62-133(b)." (Tr. vol. 21, 131.) But that classification of CCR Costs as "deferred expense" was upon a fully litigated record rejected by the Commission in the Company's prior case as "not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting." (2018 DEC Rate Order, at 289.)

The Public Staff also relies on two additional factors to induce the Commission to exercise what the Public Staff contends is the Commission's discretion to deny a return: (1) intergenerational equity, and (2) an asserted "history" of sharing of extremely large costs, exemplified according to the Public Staff by cases involving the cost of environmental cleanup of manufactured gas plants and the cost of abandoned nuclear generation facilities. Even assuming that the Commission has the discretion to deny a return, neither of these factors is persuasive.

1. Intergenerational Equity

The Public Staff asserts that intergenerational equity considerations apply (Tr. vol. 21, 131), which is a follow on to its argument that CCR Costs are not "used and useful" because they relate to service to customers in the past, with no benefit to present and future customers. But intergenerational equity considerations make no sense in the context of the Company's coal ash basin closure costs, all of which have been incurred since December 31, 2014 as a result of changes in the law and for purpose of complying with legal requirements that did not even exist prior to the passage of CAMA in 2014. The costs recovered in the Company's prior case related to the period from January 1, 2015 through December 31, 2017; the costs in this case relate to the period from January 1, 2018 through January 31, 2020. No customer in "past decades," to use witness Maness' term (Tr. vol. 21, 131), would ever had had to pay CCR Costs, because those particular costs did not even exist, and would not have existed, prior to the time the legal requirements for management of coal ash changed in 2014.

Properly understood, intergenerational equity concerns are completely different, and were explained by the Supreme Court in *State ex rel. Utils. Comm'n v. Edmisten*, 291 N.C. 451 (1977). This case involved a gap in the General Assembly's enactment of a fuel adjustment clause. The gap rendered fuel costs incurred by the utilities operating in North Carolina for several months immediately prior to the enactment's effective date uncollectible without relief from the Commission – specifically, a surcharge upon rates to billed in the months following the statute's effective date. The Commission granted permission for the surcharge, but the Supreme Court reversed. Noting (291 N.C. at 469) that prospective ratemaking, either to recover unexpected past expense or to refund expected past expense that did not materialize, was not authorized by the Public Utilities Act, the Court held

> Such rate making throws the burden of such past expense upon different customers who use the service for different purposes than did the customers for whose service the expense was incurred. For example, the surcharge here in question requires Duke's customers in the winter months to pay more than they otherwise should pay for their service because of the cost of coal burned in July and August in supplying electricity for air conditioning.

(Id. at 470.) Here, by contrast, there is simply no "past expense" to burden present or future customers – CCR Costs in this rate case, which were deferred by express order of the

Commission, are currently deferred costs, not yet in rates, being sought for recovery from current and, during the Amortization Period, future customers of the Company.

2. The Manufactured Gas Plant and Nuclear Abandonment Cases

Citing to cases involving the cost of environmental cleanup of manufactured gas plants and the cost of abandoned nuclear generation facilities, the Public Staff through witness Maness asserts that there is a "history" of sharing "extremely large costs that do not result in any new generation of electricity for customers." (Tr. vol. 20, 499.) The Public Staff misreads these cases, but even more fundamentally, the Public Staff through this argument imports into the Public Utilities Act a notion ("extremely large costs") that simply does not exist in the Act. Referring in its 2018 Order to testimony from a Company witness who testified in the prior case, the Commission has already held:

> Witness Maness overstates his position – as witness Wright notes, there is "no provision of Chapter 62 requiring different treatment for 'extremely large costs'" (Tr. Vol. 12, pp. 156-21–156-22), and, witness Wright detailed any number of "extremely large cost" items not associated with new generation for which cost recovery is routinely allowed. Id. ***The Commission determines that this is another example of the arbitrariness inherent in the Public Staff's sharing proposal.***

((2018 DEC Rate Order, at 275) (emphasis supplied).) But, in any event, the Public Staff misreads and misapplies both the manufactured gas plant and nuclear abandonment cases, none of which have any relevance to the specific subject at issue – whether the Commission either may or must award the Company a return on the unamortized balance of CCR Costs during the Amortization Period.

MGP Case

The manufactured gas plant case (MGP Case) referenced by the Public Staff is the Commission's Order Granting Partial Rate Increase, Docket No. G-5, Sub 327 (October 7, 1994) (MGP Order). This case was addressed by the Commission in its 2018 DEP Rate Case Order. The Commission, noting that the precedent was of questionable validity in the first place, nevertheless held that it was distinguishable. (2018 DEP Rate Case Order, at 192-93.) In the Company's prior case, the Commission likewise found the MGP Order neither controlling nor persuasive. (2018 DEC Rate Order, at 277.)

There are indeed many distinguishing features between DEC's current case (and the coal ash cases generally) and the MGP Case. The coal ash cases involve asset retirement obligations arising from a change in legal requirements. AROs did not even exist in 1994, and the environmental cleanup costs at issue in the MGP Case did not arise in connection with asset retirement. As the Commission held in the 2018 Order, the MGP Case did not "address billions of dollars of CCR remediation costs incurred to comply with EPA and CAMA requirements accounted for in a deferred Commission approved ARO." (Id.) Moreover, basin closure costs or beneficiation facility construction costs are not "environmental cleanup" costs that were the subject of the MGP Case in any event. (Cf. id.

("The Commission is unable to discern whether the natural gas utility was required to construct lined landfills in which to place contaminated materials or construct caps over any existing repositories.").)

Further, the Commission noted that its ratemaking treatment gave the gas utility an incentive to minimize cleanup costs (MGP Order, at 23) – a factor not present in the coal ash cases, as coal ash costs are driven not by DEC or by DEP but by their environmental regulator, DEQ. Moreover, the Commission noted that its ratemaking treatment would incentivize the gas utility to pursue third-party contributions to cleanup costs. Multiple additional parties, prior owners of the sites in question, were potentially responsible under the applicable state and federal laws and regulations driving the need for environmental cleanup, for at least a share of the costs (id., at 20), and the Commission clearly did not want to dis-incent the gas utility from pursuing those parties by having customers pay the entirety of the costs. (Id., at 23.) Finally, the old MGP sites had not been operated in twenty years as of the time of the MGP Order, and so were clearly not "used and useful" in any sense – by contrast, CCR Costs are "used and useful" and a return consisting of financing costs on unamortized CCR Costs during the Amortization Period is therefore appropriate.

Abandoned Nuclear Plant Cases

The abandoned nuclear power generation cases – exemplified by *Utilities Comm'n v. Thornburg,* 325 N.C. 484 (1989) (*Thornburg*) – are similarly inapposite. They were also extensively discussed in the last round of rate cases. (See, e.g., 2018 DEC rate Order, at 276, 280-83); 2018 DEP Rate Order, at 190-92.)

In *Thornburg,* this Court concluded that the portion of common facilities at the Shearon Harris Nuclear Plant that were built to accommodate reactors that were later abandoned are excess facilities. Consequently, these excess facilities could not be included in rate base, because they were not used and useful. The coal ash cases do not involve excessive facilities tied to nuclear units that were never completed and never used to generated electricity. Instead, the coal ash cases involve investor-funded expenditures with a direct relationship to power generation – the utilities' system to address coal ash residue resulting from decades of electricity generation. When new regulations required changes to that system, investor funds were used to modify that system and those modifications were property capitalized as "electric plant utilities." Those investor funds that have been expended (and properly deferred by the Commission) are directly linked to property that was used and useful in rendering services to the public, and, as we have seen, are themselves used and useful in rendering service to the public.

In the 2018 Order the Commission noted that as to the nuclear abandonment cases, to the extent relevant at all, their relevance goes to the propriety of "equitable sharing," not the return on any unamortized balance of CCR Costs. (2018 Order, at 276.) The Commission also noted that the Supreme Court rejected equitable sharing. (Id., at 281-82.)

The nuclear abandonment cases involve the utility's decision to make an investment that, for reasons unrelated to imprudence or mismanagement, becomes uneconomic. This was described by witness Fetter in his testimony, in the context of a hypothetical jurisdiction wrestling with the fallout of the Three Mile Island incident upon construction of nuclear generation. (Tr. vol. 26, 145-46.) There may be good reason in such a circumstance to not visit the entire economic consequence of the investment decision upon customers, and the "used and useful" requirement – for those jurisdictions that have it – proved to be one means of ensuring that the entire economic consequence of an ultimately uneconomic investment be visited upon customers. (Id.)

CCR Costs are not, however, an investment chosen by DEC or its management in the way that DEC chose to invest in (and then abandon in the wake of Three Mile Island) additional nuclear generation. To the contrary, CCR Costs are costs required by changes in the law – costs that the Company must incur, because failure to comply with the law is not an option for the Company. The nuclear abandonment cases, therefore, do not address the specific return issues with which the Commission grappled in DEC's prior case, or that the Commission is once again grappling with in this case. The Commission correctly decided in the 2018 Order that the nuclear abandonment cases were inapposite. Nothing has changed, and it comes to the same conclusion again.

E. Dominion Order

Some parties have cited to and relied upon certain portions of the Commission's 2020 Dominion Rate Order. Specifically, parties have cited to this Commission determination that Dominion was entitled only to a recovery of but not on Dominion's CCR basin closure costs. This Commission notes, however, that the 2020 Dominion Rate Order does not govern the outcome of the present case. First, each rate case must be decided in consideration of the record evidence in that case. The record evidence in this case certainly supports a return on the unamortized balance of CCR Costs during the Amortization Period. Second, the Commission must in this case pay heed to the investor expectations embedded in the 2018 Order. There is nothing comparable with respect to the question of a return "on" for Dominion.

As the Commission stated in the Dominion Order, its decision was "based on the [Dominion] record as a whole … [and its legal conclusion was that] it is appropriate to treat the [Dominion] CCR costs as deferred operating expenses and not as costs of property used and useful within the meaning and scope of N.C.G.S. § 62-133(b) … ." (2020 Dominion Rate Order, p. 134.) The Dominion record included evidence that that Dominion's CCR costs were properly classified as operating expense. (Id. (Dominion witnesses indicated that roughly 98% of the deferred expenditures would have been classified as operating expense in the absence of ARO accounting).) There is nothing comparable in the evidentiary record in this case. To the contrary, both Company witnesses David Doss and Sean Riley testified that DEC's coal ash costs were all properly and appropriately classified as capital costs. (See Doss: Tr. vol. 22, 247, 249-50; Tr. vol. 23, 33-34; Riley: Tr. vol. 23, 161-62 ("asset retirement cost is not a separate asset of the company, but rather it's part of the operating asset, the long-li[v]ed asset it's associated with …"); 177 ("asset retirement cost, an asset … [is not a] separate intangible asset … but rather that asset retirement cost is part of the coal facility itself."), 178-79 (when ARO initially established, the asset is non-cash, and therefore not in rate base, but at the point where cash is expended the "spent regulatory asset" is recoverable from ratepayers, and as the Company has "used shareholder funds …[it] should earn a return on that spent regulatory asset.”).) There is no evidence to the contrary save Public Staff witness Maness’ testimony that the costs are deferred expense – testimony that this Commission has already determined to be “not persuasive, not supported by authority and not determinative … [and] also incorrect as a matter of accounting.” (2018 DEC Rate Order, at 289.)

Further, in the Dominion Order the Commission relied upon a number of historical studies of which it took judicial notice. (2020 Dominion Order, at 127-29 and 132.) These were not introduced into evidence during the evidentiary portion of the Dominion hearings. The situation in the current DEC case is completely different – the cited studies, along with others, featured prominently in pre-filed testimony from multiple parties, and were heavily discussed an analyzed at DEC’s evidentiary hearing. For example, among the cited studies are two EPRI manuals, *EPRI Coal Ash Disposal Manual* (2d ed. 1981) and *EPRI Manual for Upgrading Existing Disposal Facilities* (Aug. 1982), which were marked and introduced in the DEC case as, respectively, Joint Ex. 7 and Joint Ex. 8. Both EPRI manuals were the subject of extensive testimony from Company witness Marica Williams, among others. (See Tr. vol. 27, 150-52.) Witness Williams indicates in her testimony that neither manual is particularly instructive with respect to the issues posed in this case.[46] The 1981 Manual, for example, is written as guidance for designing new disposal facilities, not applicable to existing operating facilities” (id., 150), and she noted specifically that the manual itself stated that EPA at that time had concluded that coal ash was “of relatively low concern.” (Id.) As for the 1982 Manual, which focused on upgrading existing disposal facilities,[47] she noted that the document itself announced at its very beginning that the applicable rules were in a state of flux, and that, therefore, “it may be premature for any utility to embark on a program to update their existing disposal facilities.” (Id., 152.)

Another of the historical studies referenced in the Dominion Order is the 1988 EPA Report to Congress (Joint Ex. 13). No matter what the earlier EPRI manuals may have said on the subject of coal ash management, the 1988 Report provided a comprehensive overview of coal ash management practices made EPA’s conclusions and recommendations regarding ash management. In short, the 1988 Report was “state of the art” for its time – and state of the art prepared by the very office at EPA led by witness Williams. If there is a single witness who lived that era at EPA who testified in this case, it is witness Williams. As she noted, in the 1988 Report EPA concluded that no change was necessary to then-current coal ash waste management practices, inasmuch as those practices “appear[ed] adequate for protecting human health and the environment.” (Joint Ex. 13 at 7-11.) And, as witness Williams also noted, EPA in crafting its 1988 Report was well aware that then-current waste management practices included, particularly in the

[46] A later EPRI manual, published in 2004, was also referenced in the Dominion Order (at 128-29), and was discussed in detail earlier in this Brief. It is also not instructive with respect to the issues posed in this case, as the discussion above concerning Georgia Power’s Plant Arkwright shows.

[47] All of the Company’s ash basins had been constructed by 1982.

Southeastern United States, unlined ash ponds. The Commission did too, in the 2018 Order.

The 1988 Report is instructive in other ways. In their references to the historical studies generally (Joint Exhibits 1-13) Intervenors ignored the conclusions reached by any particular study and merely cherry picked an individual sentence or two from the study that they felt advanced some argument they were making. Witness Quarles provides an object example. His pre-filed testimony cited to the 1988 Report, and stated that a "key conclusion" of that Report was that "The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause groundwater contamination." (Tr. vol. 18, 36.) But, as witness Quarles admitted on cross-examination that "key conclusion" is nowhere to be found in the actual conclusions of the Report, which were set forth in Chapter 7 of the Report. (Tr. vol. 18, 115-16.) Witness Quarles' treatment of the 1982 EPRI Manual (Joint Ex. 8) is similar. In his pre-filed testimony he quotes from the Manual:

> In 1982, EPRI made clear that regulatory compliance by itself might not ensure environmental protection and advised that utilities must achieve both, noting that "[p]otential deficiencies in utility waste disposal practices may be defined by two sets of standards: [1] The disposal practice does not comply with specific federal and/or state regulatory requirements; [2] The site has the potential to contaminate the environment." (1982 EPRI Manual at 4-1.) Accordingly, EPRI reached this conclusion: "[a]n engineering assessment of site adequacy must therefore address (1) whether the operation complies with prevailing regulations, and (2) whether the site poses a threat to the local environment. Both problems must be addressed simultaneously." (1982 EPRI Manual at 4-2.)

(<u>Id.</u>, 38.)

The obvious inference from the quotation that witness Quarles wished to draw is that simply complying with environmental regulation is not necessarily good enough, one must in addition do more than merely comply when a site poses the threat of environmental "contamination." But what the authors of the Manual meant by "contamination" is very important to a full understanding of what their recommendations meant – and no one, certainly not witness Quarles, knows what they meant by "contamination." (<u>Id.</u>, 92-93.) This is a key distinction, because whether "contamination" is of the type that could cause environmental harm – that is, harm to the public health and welfare, for example by threatening drinking water – or is merely a regulatory issue is crucial to fashioning an appropriate response, as witness Wells testified. (Tr. vol. 28, 102-03.) Public health risk requires quicker action; a regulatory issue alone requires working with the regulator – in this case, DEQ – to fashion an appropriate solution. DEC did both.

Moreover, in the 1981-82 period in which the EPRI Manuals were published, the evidence in DEC's case proves beyond a shadow of doubt that DEC, in the face of the types of concerns regarding the potential for environmental contamination from ash ponds, investigated its ponds, and facilitated the EPA in investigating its ponds. The Company began groundwater monitoring at the Allen Plant in 1978, in partnership with EPA. (Tr. vol.

27, 37.) The Allen Plant was also selected for study by the EPA, conducted through a contractor, Arthur D. Little, Inc., inasmuch as EPA viewed it as representative of sites located in the Piedmont region. (Id. at 37-38.) The Company conducted leachate studies for the purpose of assisting regulators in developing future groundwater standards that could be used at the regional or state level. (Id. at 37.)

Both studies – DEC's internal work, performed on a voluntary basis, and Arthur D. Little's work performed on behalf of EPA – concluded that the wet sluicing of coal ash to Piedmont region ponds did not have a significant impact to groundwater: "And the key conclusion, not just from Duke's internal voluntary work … [but also the] A. D. Little work, was the same. And that is the impacts were localized, they weren't seeing a risk, they weren't seeing a significant impact." (Id., 236.) Witness Quarles chose to ignore the conclusions of the actual studies, as reported in their executive summaries. Instead, he called the conclusions "bad information." (Tr. vol. 18, 99.)

Witness Quarles and other Intervenor witnesses may have the luxury of ignoring the actual findings of the studies they bring to the Commission's attention, or cherry picking from massive studies to fixate on a random sentence or two within them. The Commission does not. Should it choose to rely on evidence such as technical reports and scientific literature, it must thoroughly review the reports and literature, not review them in a cursory manner. It must take into account negative evidence from the reports and literature, not simply sweep such "evidence under the rug." *National Audubon Society v. Department of the Navy*, 422 F.3d 174, 194 (4th Cir. 2005). If it fails in these tasks, it risks a reviewing court finding it to have acted arbitrarily and capriciously. (Id. at 187.)

The second reason not to import the Dominion case result into this case is the fact that investor expectations were not embedded into the Commission's prior rulings with respect to Dominion's CCR costs. Unlike DEC's current situation, Dominion's prior case (decided in 2016, in Docket No. E-22, Sub 532) was not fully litigated and did not have a significant evidentiary record (2020 Dominion Rate Order, at 123), and so the Commission minimized the prior case's precedential effect. (Id.) The Commission's decision in Dominion's prior case certainly did not have any language even remotely similar to the language in the 2018 DEC Rate Order that creates investor expectation – the language quoted above and re-quoted here that did not merely endorse spend/defer/recover but requires it, and the language that indicates that in future cases, barring a future finding of imprudence, the Commission "will" authorize a return "on" incurred and deferred CCR Costs brought into rates over time in an Amortization Period:

> … CCR remediation costs incurred by DEC during the period rates approved in this case will be in effect shall be booked to an ARO that shall accrue carrying costs at the approved overall cost of capital approved in this case (the net of tax rate of return, net of associated accumulated deferred income taxes). The Commission will address the appropriate amortization period in DEC's next general rate case, and, unless future imprudence is established, will permit earning a full return on the unamortized balance.

(2018 DEC Rate Order, at 322-23.) The Company's next general rate case is this case. The Commission will decide the appropriate amortization period over which CCR Costs are to be brought into rates. But the Commission needs to hew to its promise that a full return – a WACC return – be earned on that balance. It does so.

Discussion of Question #4: Discrete Fault-Based Disallowances and Public Staff Prudence Disallowances

Discrete Fault-Based Disallowances

Alleged Environmental "Violations"

The Public Staff, through witness Junis, asserts that disallowance of the Company's costs related to groundwater at Belews Creek is justified because these costs flow from "violations" of the law. In addition, the Public Staff and the Attorney General's Office, through witness Hart, assert that the Commission should disallow costs related to provision of permanent water supplies for similar reasons. Both are a continuation of the fault based culpability standard and fail to substantiate a disallowance. As discussed previously in this Order, the Commission rejects the Public Staff's and Attorney General's Office's proposed fault based disallowances as the evidence does not support a finding that DE Carolinas violated the law, nor does it support a finding of imprudence with respect to these costs. This finding is consistent with the Commission's 2018 Order, in which the Commission found that the costs related to groundwater extraction and alternative water supplies were prudently incurred and, accordingly, recoverable in rates.

1. Groundwater Treatment Costs

As Company witness Bednarcik explains, the Company has incurred a total of $1,793,511.72 related to its extraction well system at Belews Creek. The vast majority of these costs—$1,495,078.43—were recovered as part of the 2017 rate case, and the Company is now seeking to recover the remaining costs of $298,433.29 in the instant case. Notwithstanding that the Commission already found these very same costs to have been prudently incurred and recoverable in the previous rate case, the Public Staff, through witness Junis, asks the Commission to take a "fresh look" at its treatment of these expenses.

The premise of witness Junis' argument for disallowance of these costs, however, is nearly identical to the one he advanced on behalf of the Public Staff in 2017—that the Company's installation of extraction wells at Belews Creek pursuant to the terms of the September 2015 Settlement between DEQ, DEC, and DEP (the "Sutton Settlement Agreement") would not have been necessary under CAMA absent violations of the state's groundwater standards. The Commission has already rejected this rationale once. As witness Junis acknowledges in his testimony, the Commission directly addressed the Sutton Settlement Agreement in its 2017 Order, stating that it "declines to find that [the Sutton Settlement Agreement] evidences violation of environmental obligations" and that "there is insufficient evidence that [DEC] would have had to engage in any groundwater extraction and treatment activities absent the obligations imposed upon it by CAMA and/or the CCR Rule." 2017 DEC Order at 297, 300. Importantly, the Commission found that "the assertion that DEC's violations' resulted in the [Sutton Settlement Agreement] and in groundwater extraction and treatment costs that would not otherwise have been incurred is incorrect and not supported by the evidence." (Id. at 300.)

Consistent with the 2018 DE Carolina Rate Order, the Commission again declines to find that the DEQ Settlement Agreement evidences violation of environmental obligations. As noted in the Commission's 2018 Order, the DEQ Settlement Agreement references in its recitals a DEQ "Policy for Compliance Evaluations" promulgated in 2011, and it appears from the recitals and their description of that Policy that there was a very serious question as to whether any violation of the State's groundwater standards had occurred. (*See* DEQ Settlement Agreement, at 3, 4-5.) The recitals also indicate, with the passage of CAMA, that the Company would be required to close its coal ash basins, and that CAMA "dictate[d], in detail a procedure for assessing, monitoring and where appropriate remediating groundwater quality in areas around coal ash impoundments in North Carolina …." (Id. at 3-4.) Further, in the recitals the DEQ acknowledged that the CAMA requirements were "designed to address, and will address, the assessment and corrective action" associated with alleged groundwater contamination.

In support of his contention that the Commission should reverse course on its previous ruling, witness Junis points to the fact that groundwater exceedances measured at Belews Creek have increased from 1,926 in 2017 to 3,972 today. (Tr. vol. 20, 458.) In response, Company witnesses Bednarcik and Wells contend that witness Junis' reliance on these numbers is indicative of a basic misunderstanding of the 2L exceedance/violation process. (Tr. vol. 24, 92-93.) According to witnesses Bednarcik and Wells, an increase in measured exceedances does *not*, as witness Junis contends, suggest an increase in groundwater contamination in and around the Belews Creek plant. Rather, the increased number simply indicates that sampling is ongoing at both pre-existing and new wells while the Company engages in preparing and implementing a corrective action plan in cooperation with DEQ and as required under CAMA. In this way, witnesses Bednarcik and Wells explain, an increased number of exceedances is not unexpected while the Company works with DEQ toward corrective action.

The Commission finds the testimony of Company witnesses Bednarcik and Wells to be persuasive with respect to the Public Staff's proposed disallowance of groundwater costs and entitled to substantial weight. In particular, the Commission is persuaded by the testimony of witnesses Wells and Bednarcik that the Public Staff's focus on the raw number of exceedances measured over time ignores the iterative nature of comprehensive site assessment. Witness Wells explained that measuring exceedances at different locations in a plume around an activity may result in multiple exceedances of groundwater standards, but that does not result in multiple violations of the 2L rule's prohibition. Both he and witness Bednarcik explained that this distinction is important for evaluating the claim that the number of exceedances indicates a "breadth of environmental violations." (Tr. vol. 25, 128.)

2. Permanent Alternative Water Supplies

Both the Public Staff and AG recommend that the Commission disallow recovery of costs that DEC incurred to provide permanent drinking water supplies to neighboring properties. The Public Staff, through witness Junis, calculates the amount to be disallowed as $17,845,189, which calculation includes both the costs incurred to connect eligible residential properties to permanent alternative water supplies *and* the costs incurred to install and maintain water treatment systems. (Tr. vol. 20, 460-62.) The AG calculates its proposed disallowance to be $17,527,070. (Tr. vol. 16, 826; Tr. vol. 17, 38-39.) For the reasons set forth below, the Commission is not persuaded by either the Public Staff's or the AG's arguments and declines to adopt the proposed disallowances.

For his part, Public Staff witness Junis argues only that the permanent alternative water supply expenses are analogous to the costs the Company incurred to provide temporary bottled water supplies to customers—expenses which the Commission disallowed in the 2018 case—and should, therefore, be disallowed. (Tr. vol. 20, 460-62.) In response, witness Bednarcik notes that DEC's efforts with respect to installation of permanent alternative water supplies and water treatment systems were undertaken to comply with applicable law. (Tr. vol. 24, 93-95.) In particular, N.C.G.S. § 130A-309.211(c1) obligated the Company to establish permanent replacement water supplies for each household that has a drinking water supply well located within a one-half mile radius from the established compliance boundary of a CCR impoundment, and is not separated from the impoundment by a river. The statute goes on to provide that the requisite replacement water supply can be achieved either through connection to public water supplies or, in certain circumstances, through installation of a filtration system at the household. Witness Bednarcik notes that the requirement exists even absent the existence of a 2L exceedance for qualifying households and also applies to households outside the half-mile radius where such exceedances were identified. Finally, witness Bednarcik points out, and witness Junis acknowledges, that the Company is not seeking to recover the costs it voluntarily incurred to connect uncovered properties to alternative water supplies that were not subject to the requirements of CAMA.

The Commission is persuaded by witness Bednarcik's testimony and finds that DEC complied with the letter of the law with respect to installation of permanent alternative water supplies and water treatment systems. Accordingly, the Commission sees no compelling reason presented by the Public Staff to depart from its position in the 2018 Rate Case Order that these costs are recoverable.

Turning to the AG's argument, witness Hart contends that alternative water supply costs were incurred directly as a result of DEC delay in evaluating groundwater impacts to potential receptors at its sites. (Tr. vol. 16, 826; Tr. vol. 17, 38-39.)

Witness Hart does not dispute that CAMA was amended in 2016 to require DEC to provide alternative drinking water supplies to residents within a half mile of its impoundments. Further, witness Hart does not dispute that DEC is required to comply fully with CAMA and its amendments. Instead, witness Hart's recommended disallowance is based on his speculation of *why* the North Carolina legislature included the requirement. It would be improper for the Commission to engage in such speculation:

> Even if the actions or inactions of [DEC] or one of its sister companies was a direct cause of CAMA as these witnesses allege, such direct causation alone is not sufficient legal basis for disallowing otherwise recoverable costs. If the North Carolina General Assembly had intended to give the Commission the authority to deny otherwise recoverable environmental compliance costs due to some punitive theory of causation, it could have said so—and it did not.

2017 DEC Rate Order, at 272. Even if the Commission were to engage in witness Hart's mind-reading exercise, his theory rests on flimsy grounds. Months prior to the adoption of the CAMA amendment, the Executive Branch agency responsible for public health, the Department of Health and Human Services (DHHS) rescinded drinking water advisories for properties near DEC's sites determining that ash basins did not pose a risk to the safety of residents' drinking water. (Tr. vol. 17, at 47-50.) The legislature, nevertheless, determined that further protections were needed. But had lack of reliable data been the motivating factor for the legislature's inclusion of this requirement, as witness Hart suggests, certainly being presented with conclusive data showing no contamination of receptor wells would have caused the legislature to rescind this requirement. (Tr. vol. 28, 119.) The legislature has not done that, which shows the folly in attempting to ascribe motive or intent to legislative policy decisions in the absence of any express statement of intent.

<u>I. Public Staff's Prudence Disallowances: Overview</u>

The Commission's framework requires a detailed analysis before any costs can be disallowed on the basis of findings of imprudence. 2018 DEC Rate Order, 294. The Public Staff attempts such an analysis of the Company's coal ash costs, and based on that analysis presents several discrete and specific proposed sets of disallowances. Through the testimony of witnesses Garrett and Moore, the Public Staff argues that the Company acted imprudently and unreasonably with respect to management of CCR compliance activities at the Riverbend, Dan River, and Buck Plants, and contends that the Company should have selected different management approaches and/or different approaches to contractual negotiations, thereby saving costs. In particular, the Public Staff recommends the following disallowances: including: (1) payment of a fulfillment fee to Charah related to the disposal of ash from the Riverbend plant at the Brickhaven structural fill ($46,142,699) (Tr. vol. 20, 217, 247.); (2) payment of "premium rates" for ash excavation and disposal at the Dan River Steam Station ($29,250,905) (Tr. vol. 24, 51.); and (3) construction costs at the Buck Beneficiation plant ($67,809,160). (Tr. vol. 20, 191.)

The Commission determines not to accept these discrete disallowances based upon the testimony of Company witness Bednarcik which the Commission credits and to which the Commission attaches substantial weight. Historically—and, in particular, in the 2018 DEC Rate Order and the 1988 DEP Rate Order—this Commission has stressed the importance of carefully examining the Company's explanations of the decisions it made, as of the time they were made, and emphasized the credibility of the decision-makers, particularly in juxtaposition to after-the-fact analyses presented by Intervenor-retained consultants. *See*, *e.g.,* 2018 DEC Rate Order at 302; 1988 DEP Rate Order, 29. While the Commission does not question the expertise of Garrett and Moore, it is persuaded by witness Bednarcik's testimony that Garrett and Moore missed or overlooked pertinent facts and real world conditions in their recommendations, and that their discrete disallowances are therefore unwarranted.

Like witness Kerin's testimony in the 2018 case, witness Bednarcik's testimony regarding the Company's decisions is entitled to substantial weight— more weight than after the fact evaluations from Garrett and Moore. Witness Bednarcik expressed a full and complete understanding of the issues and has been living and breathing the CCR closures in her role as Vice President of Coal Combustion Products, Operations, Maintenance, and Governance, overseeing the Company's compliance program. (Tr. vol 15, 64-66; Late Filed Exhibit 7 (listing Duke Energy employees and former employees who informed witness Bednarcik's testimony, knowledge, and understanding of the Company's current and historic environmental compliance and coal ash practices). Witnesses Garrett and Moore's recommended disallowances were challenged at the hearing through cross-examination. These witnesses were unable effectively to support their positions while on the witness stand. Similar to the Commission's findings in Docket E-7, Sub 1146, witnesses Garrett and Moore have once again "overlooked pertinent facts and real-world conditions in their recommendations." (Tr. vol. 20, 350.) Therefore, the Commission determines that their recommendations are deficient on the basis of a lack of credibility.

__Payment of Charah Fulfillment Fee__

By way of background, witness Bednarcik explains that the Companies executed the contract with Charah on November 12, 2014, with the intent of securing a location at which to dispose of CCR from DEC's Riverbend plant and DEP's Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants. (Tr. vol. 24, 54.) Time was of the essence to secure such a location, according to witness Bednarcik, because both the Riverbend and Sutton sites were classified as "high priority" sites under CAMA with an excavation deadline of August 1, 2019. **[BEGIN CONFIDENTIAL]** [redacted]

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Nearly two years after the Companies executed the contract with Charah, the North Carolina Legislature passed an amendment to CAMA that required the Company to construct beneficiation plants at three Duke Energy locations, capable of producing 300,000 tons of ash a year from each plant for use in the cement industry. (Id. at 51.) Between December 2016 and June 2017, the Companies announced that Buck, H.F. Lee, and Cape Fear would serve as the three beneficiation sites, (Id. at 55.), an arrangement witness Bednarcik explains severely reduced the ash available for transport to the Brickhaven and Sanford Colon mines. (Id.) As a result, the contract was deemed terminated on May 29, 2019 after just 7,342,409 tons of ash had been actually excavated and triggering the fulfillment fee provisions. (Id.)

For its part, the Public Staff, through witness Garrett, contends that the fulfillment fee was unreasonable because it was calculated using what witness Garrett believes was an incorrect denominator. And for the reasons described in more detail below, the Commission is not persuaded by this argument, and instead gives substantial weight to the justification provided by witness Bednarcik.

First, witness Garrett's purported calculation methodology disregards the plain language of the contract and improperly attempts to re-write a key provision. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Witness Garrett acknowledged on cross-examination that the Master Contract explicitly lays out the appropriate calculation of the prorated cost as negotiated by the Parties, leaving no ambiguity. (Tr. vol. 20, 341-42). Yet despite this clear language, witness Garrett proposes an alternative calculation, essentially supplanting the contractual terms of a provision fully negotiated between two sophisticated Parties with his own terms. (Id. at 343.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Witness Garrett's proposal demonstrates a fundamental misunderstanding of general principles of contractual construction. *RL REGI N.C., LLC v. Lighthouse cove, LLC*, 367 N.C. 425,428, 762 S.E.2d 188, 190 (2014) (finding that the court looks to "the plain meaning of the written terms" in order to "determine the intent of the parties."); *Ussery v. Branch Banking & Tr. co.*, 368 N.C. 325, 335, 777 S.E.2d 272, 279 (2015) (finding that the meaning of a contract is "gathered from its four corners."). Moreover, the Commission notes that the law is clear in North Carolina that when sophisticated parties like Duke and Charah engage in a protracted negotiation process where each party has equal bargaining power to alter language ambiguities are not, as a rule, construed against the drafter and, instead, terms are given the meaning the parties intended. *Joyner v. Adams*, 87 N.C. App. 570, 361 S.E.2d 902 (1987) (rejecting the rule to construe ambiguities against the drafter because "the language was assented to by parties who had both the knowledge to understand its import and the bargaining power to alter it.")

Here, as witness Bednarcik explained, both Duke and Charah negotiated at arms-length the appropriate inputs for the prorated cost calculation. (Tr. vol. 25, 83.) Further, the termination provisions of the Master Contract were carefully tailored to ensure that the development cost at Brickhaven and Sanford Clay Mines were appropriately apportioned between the parties. Thus, the 20 million denominator is the correct number for calculating the prorated percentage and, by extension, the prorated costs. (Tr vol. 24, 57.) Witness Garrett cannot now replace one contractual term for another post execution, and the Commission rejects his proposed disallowance on those grounds.

Moreover, the Commission finds that there are several other provisions in the contract that support the as-written formula for pro-rated costs. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Second, even if it were possible to *ex post facto* rewrite the contract as witness Garrett suggests, the Commission is persuaded by evidence presented by witness Bednarcik that the Public Staff's proposal for calculating the fulfillment fee likely would not have induced Charah—or *any* qualified contractor—to enter into the contract for ash disposal. As witness Bednarcik explained, for a contractor to invest a large amount of capital, such as in the development of significant infrastructure in order to be able to perform the needed contracted service, it is common practice and reasonable to require a minimum investment by the company requesting the contracted service. (Tr. vol. 24, 172.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

The Public Staff, both through witness Garrett and cross-examination of witness Bednarcik, attempted to assert that Charah had already recovered its development costs through payment of the purchase orders issued under the Master Contract and that payment of the fulfillment fee duplicated its cost recovery. However, witness Bednarcik's testimony is clear that Charah did not recover twice for the cost of development. (Tr. vol. 25, 51.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** As witness Bednarcik explained having some portion of development cost paid through purchase orders is not inconsistent with the recovery of those cost through the prorated cost provisions of the agreement. (Tr. vol. 25, 50). Indeed, as she explained the whole plan was that Charah would be compensated for their sunk costs, and in the present case, some were recovered through purchase orders, but the vast majority of it was recovered through the fulfillment fee. (Id.)

While witness Garrett is correct that DEC was not financially committed to provide Charah with quantities of ash for *excavation* beyond those identified in the purchase orders, this does not change the fact that the Company was still financially obligated to make Charah whole for prorated costs per the prorated cost triggering event definition in the Master Contract. On cross-examination of witness Garrett it was shown that the utilization of the denominator he proposed for the prorated cost calculation would work an absurd result that no counterparty would reasonably accept. (Tr. vol. 20, 345-49)

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To assume any competent commercial entity would have undertaken development, purchased two mines, developed a rail delivery system without any substantial assurance of cost recovery for such investment is unreasonable. (Id.)

Finally, witness Garrett failed entirely to rebut witness Bednarcik's testimony that the Company took reasonable steps to mitigate the potential magnitude of the fulfillment fee, both through the crafting of protective contractual terms and negotiations following termination. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

When the fulfillment fee was triggered, the Company went beyond the bargained for caps in seeking to mitigate exposure and initiated negotiations to further reduce the final fulfillment fee. (Tr. vol. 21, 59.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** In that regard, the agreement fully contemplated a process to review and negotiate the cost that would be subject to the prorated cost provision. This contracting approach is not unusual in this commercial context and was necessary due to the inability to fully identify each and every potential item of prorated cost at the inception of the contract.

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In sum, witness Bednarcik's testimony demonstrates that the Company's actions and real time decisions negotiating the Charah Master Contract and post-termination fulfillment fee were in fact reasonable and prudent, and the fulfillment fee cost was prudently incurred to allow the Company to proceed with beneficiation as required by CAMA. The Commission therefore rejects the Public Staff's proposed disallowance of the fulfillment fee.

Alleged "Premium Rates" at Dan River Steam Station

Witness Garrett next argues that the Commission should disallow $29,250,905 from the costs the Company incurred for basin closure at the Dan River plant. (Tr. vol. 20, 246.) In particular, witness Garrett takes issue with the Company's decision to terminate its contract with Parsons Environment & Infrastructure Group Inc. (Parsons) to handle the excavation of coal ash at Dan River and to hire a different contractor, Trans Ash Inc. (Trans Ash), to complete the work. Witness Garrett argues that the Company's decision to switch contractors resulted in unnecessary delays, which caused Trans Ash to complete the work on a shorter timeline, increasing costs. Witness Garrett contends that these additional costs were avoidable had the Company addressed problems with Parsons earlier.

While it is undisputed that the Dan River excavation project encountered some challenges including things like weather, implementation of dewatering and excavation, and contractor performance. Facing challenges on projects of this scope and magnitude are not uncommon. As witness Bednarcik explained, "in project management that's what you do. You look at the schedule, you look at cost, you look at scope. And so [the Company is] always managing all three of those to make sure that [it] understand[s] what the objectives are, and [the Company] work[s] with the contractors to" achieve those goals. (Tr. vol. 25, 57). Importantly, the Commission's evaluation focuses upon the Company's management of these challenges, including specifically the delays attributable to Parsons. Based upon the evidence presented, the Commission finds that the Company acted prudently in its management and termination of Parsons, and in taking the steps necessary to complete the work at Dan River on the CAMA mandated timeline. The Court Appointed Monitor's report dated September 14, 2018 explains the causes of the delays encountered by Parsons in some detail. For example, in May 2018, Parsons landfilled ash that did not meet moisture content specifications and thus necessitated significant rework. That same incident caused a subsequent breach in the landfill that required weeks of remediation. (Tr. vol. 24, 64.)

Parson's operations were also negatively impacted by a season of unusually high rainfall. On several occasions, rainfall of less than 0.2 inches in a 24-hour period caused Parsons' operations to grind to a halt for a day or more while waiting for improved conditions during daylight hours. Parsons also routinely took longer than anticipated to complete its scheduled work due to short staffing and poor coordination of subcontractors and equipment suppliers. (Id. at 64.) The cumulative result of so many setbacks, witness Bednarcik explains, was to erode the Company's buffer to complete excavation at Dan River before the August 19, 2019 CAMA deadline. (Id. at 65.)

While witness Garrett argues that the lion's share of delays occurred through no fault of Parsons, the Commission finds credible the testimony of witness Bednarcik that the Company acted prudently in its management of Parsons and exhausted its options before terminating Parsons. In particular, witness Bednarcik explains, the Company actively worked with Parsons to address and remediate the continued delays to the CCR excavation project. For example, the Company allowed Parson's site leadership team to visit the Sutton excavation site, and the Company leadership in charge of the Sutton and Riverbend ash excavation projects met with Parsons leadership at Dan River and provided means and methods details of their operations to Parsons. (Id. at 66.) The Company also assisted Parsons with both development of a stockpile management plan and a landfill weather resistant plan. In addition, the Company had Parsons prepare and implement various Recovery Plans (pursuant to the contract). In fact, in the period from March 16, 2018 to August 16, 2018, Parsons submitted six recovery plans to the Company with the last plan submitted just a year before the CAMA-mandated deadline. Interestingly, witness Garrett did not even review any the recovery plans or sequenced excavation plans submitted by Parsons prior to reaching his recommendation in this case. (Tr. vol. 20, 265). One would think a full understanding of the recovery and sequenced excavations plans would be important in assessing Parsons' performance and the Company's actions. While some of the actions within the Recovery Plans resulted in schedule gains, the net impact of Parsons' strategy did not recover the schedule, and Parsons fell even further behind the planned completion date. (Tr. vol. 24, 65-66.)

On August 20, 2018, less than a year from the CAMA mandated deadline, the Company formally informed Parsons that, without immediate improvement, the Company would be forced to consider termination. As witness Bednarcik testified, Parsons submitted a sequenced excavation plan of the secondary basin in early September, and the DEC project team had considerable doubts regarding Parson's ability to implement that plan given its lack of success processing saturated material with any predictability or certainty. In addition, the plan submitted did not address the specifics of how Parsons would remediate the issue going forward. (Tr. vol. 25, 52.) On September 14, 2018, Duke notified Parsons that its contract would be terminated, and the contract was terminated October 12, 2018. (Tr. vol. 24, 157.) The evidence is thus abundantly clear that the Company took substantial steps to help Parsons overcome the challenges it faced prior to terminating its contract. While the Public Staff argues that the Company could have done more, the Commission is not persuaded given the totality of the circumstances, Parsons' history of delays, and the Company's imperative to meet the CAMA deadline.

Both through witness Garret and on cross-examination of witness Bednarcik, the Public Staff tried to suggest that the Company could have done more to assist Parsons and avoid the cost of termination. For example, Public Staff suggests that the increase in flow rate obtained from the City of Eden could have assisted Parsons. However, as witness Bednarcik explains the Company discussed increasing flow rate with the City of Eden yearly during the Dan River excavation and it was not until the end of 2018 that capacity became available. (Tr. vol. 25, 56.) Similarly, where Public Staff took issue with the amount paid to Parsons to terminate the contract, witness Bednarcik explained that the final amount paid in the contract termination was either for work already completed, items that Parsons had already bought on site, or termination of leases. (Tr. vol. 24,158.) Once again, real world facts foil Mr. Garrett's theory. Accordingly, the Commission concludes that it was reasonable and prudent for the Company to terminate its relationship with Parsons and contract with Trans Ash to complete the Dan River excavation work.

Witness Garrett next contends that the costs incurred by Trans Ash, including the costs to implement a 24/7 excavation schedule in January 2019, were not reasonable or prudent for a variety of reasons. The Commission rejects each of these rationales in turn.

The mitigating strategies witness Garrett proposes—including negotiation of a performance bond, and requests to collect security and back charges from Parsons—are not reasonable and demonstrate a fundamental misunderstanding of these contractual terms. He suggests that DEC should have negotiated a performance bond in its initial contract with Parsons. (Id. at 69.) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**
The Commission thus finds that neither a performance bond nor invoking the Section 4.12 would have mitigated any damages.

The remaining purported cost saving alternatives proposed by witness Garrett are likewise unworkable. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Witness Garrett next suggests that DEC "overpaid" Trans Ash by authorizing extended working hours. The weight of the evidence, however, suggests that an expanded workday was needed to complete excavation by the CAMA deadline. By working 24 hours a day, Trans Ash was able to condition the saturated dry ash with lime during the day and move the then-dry ash into the landfill at night, increasing efficiencies. This also helped mitigate delay issues associated with weather; as soon it was practicable for work to begin following weather delays, work immediately commenced no matter the time of day. (Id. at 76). Furthermore, Mr. Garrett fails to acknowledge that had Parsons remained onsite they also would have had to pursue 24/7 operations and ash conditioning in order to have any chance of completing the work by the CAMA mandated deadline. (Tr. vol. 24, 75).

Witness Garrett also makes much of the fact that the Company excavated 20,736 CY of ash from Ash Stack 2, which is not ash subject to CAMA, before the CAMA deadline. However, as witness Bednarcik notes, excavation of such ash was completed at times when there was negligible impact to schedule. Moreover, this ash was used as protection in one of the landfill cells and to facilitate beneficiation activities actually associated with CAMA. This non-basin ash quantity accounted for less than 2% of the ash that was excavated. (Id. at 76.) Otherwise, Trans Ash and Parsons did not excavate any Ash from Ash Stack 2 prior to completion of basin ash excavation.

Finally, witness Garrett suggests that the Company should have sought a variance from DEQ rather than incur costs for the 24/7 work. Here again, the Commission finds that witness Garrett's proposal is not a real world solution. Witness Garrett suggest that obtaining a variance requires "little effort" (Tr. vol. 20, 248.) However, a clear reading of the statutory provision combined by the Company's prior experience in seeking variances at Sutton suggest otherwise. As Company witness Bednarcik points out, making a variance request to DEQ does not guarantee that one will be granted, and absent such a guarantee, the Company would have had no choice but to push forward with the efforts required to meet the deadline. Indeed, CAMA is explicit that excavation efforts must proceed with haste even as DEQ considers a variance request. N.C.G.S. § 130A-309.215(a1) (where a variance is requested by an impoundment owner, the impoundment owner must "continue to apply best efforts to minimize any delays in meeting the deadline."). Scheduling issues aside, the Commission agrees with witness Bednarcik that the Company's chances of securing a variance to the excavation deadline at Dan River was questionable at best. Section 130A-309.215(a) of CAMA provides DEQ the authority to grant a variance only when "the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and would produce serious hardship without equal or greater benefits to the public." Witness Garrett's reliance upon the Sutton variance as an example highlights the difficulty in obtaining a variance. In that case, DE Progress had to establish a variety of factors to justify its requests, including (1) excavating at an average rate of 150,000 tons of ash per month; (2) expediting completion of the landfill; (3) expanding dredging operations; (4) adding a third conveyor; (5) simultaneously operating three dredges; and (6) and taking various additional measures including moving to 24/7 operations. (Tr. vol. 20, 277-78.) Here, the simple truth that Trans Ash was, in fact, able to meet the CAMA deadline using the 24/7 schedule and lime excavation indicates that the Company could and did meet the deadline using the best available technology and under the project contingency. (Tr. vol. 25, 54-55.) To the extent witness Garrett is suggesting that DEQ could grant a variance based solely upon the cost to employ the best technology cuts against the plain language of the statute.

As witness Bednarcik notes, DEP requested a variance to the CAMA deadline applicable to Sutton. Before doing so, however, DEP implemented the "best available technology" in an attempt to meet the deadline, such as requiring work 24 hours a day five days a week to exemplify DEP's need for a variance. Despite implementing these efforts and requesting a six-month extension, however, DEQ only granted DEP a four-month extension. As this Commission made clear in Docket E-2, Sub 1143 and Docket E-7, Sub 1146, the CAMA deadlines provide the overarching framework by which prudency is assessed. (cite DEC/DEP Order p305) The Company's action to comply with a CAMA deadline in this case are in fact consistent with our prior guidance in assessing prudence.

For all of these reasons, the Commission finds that the costs the Company incurred to complete excavation at the high priority Dan River site were reasonable and prudent. Accordingly, the Commission declines to impose the disallowance proposed by witness Garrett.

__Buck Beneficiation Project__

In the last of three compliance-related disallowances proposed by Public Staff witnesses Garrett and Moore, witness Moore recommends a disallowance of $67,809,160, which represents a portion of the costs incurred by subcontractor Zachry Industrial Inc. (Zachry) for Engineering, Procurement, and Construction (EPC) expenses at the Buck beneficiation site. (Tr. vol. 20, 173-74.) The crux of witness Moore's argument is that, in his view, Duke Energy should not have contracted with Zachry to perform the EPC construction work at Buck because its bid for the work was more than twice the cost estimate included in the RFI submitted by The SEFA Group, Inc. (SEFA) which contemplated that H&M Company, Inc. (H&M) would construct the beneficiation units. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** The Commission rejects witness Moore's proposed disallowance for several reasons.

First, the Commission finds that it is not reasonable for witness Moore to compare the construction estimate included in SEFA's RFI response to those included in Zachry's EPC contract as the SEFA/H&M estimate was prepared before the Company knew the final project scope. As Company witness Bednarcik explains, the purpose of the RFI was to collect general written information about capabilities of various contractors in an effort to screen contractors and help the Company make a decision on what steps to take next. (Tr. vol. 24, 81). The RFI helps the contractor as well consider their strategy for potentially submitting a formal proposal. However, it is clearly intended to be less rigorous than a request for proposal which would requires a firm commitment. In this instance, the RFI promulgated by the Company in August of 2016 for the Buck beneficiation project did not ask responding contractors for any site-specific estimate of the EPC costs to be incurred for the beneficiation sites, nor did it provide project details that would be necessary to calculate such an estimate – in large part because the Company was still developing the project's precise scope and determining the locations for beneficiation. (Id. at 81.) As such, the RFI was nothing more than an invitation to identify entities capable of undertaking the project, and respondents to the RFI provided data points readily available to help the Company assess its capabilities. The estimate included in SEFA's RFI was based on the costs it incurred, through H&M, to construct the Winyah STAR Facility in South Carolina. H&M was not the entity responding to the RFI, it was SEFA. SEFA had previously partnered with H&M to construct Winyah STAR Facility. As witness Moore appeared to agree, the use of the Winyah STAR facility by SEFA in its RFI response was just an "example." Witness Moore did *not* believe that the Company's beneficiation unit was intended to be an "identical-type facility [such that the Winyah STAR Facility] should be used as the basis." Instead, per witness Moore, the Winyah STAR Facility should only "give[ ] the people that build it an idea of what it will take to build a similar facility that meets CAMA requirements." (Tr. vol. 20, 299.)

However, the devil is in the details when comparing projects, and the ultimate detail overlooked by Mr. Moore is the CAMA requirements. As witness Bednarcik points out, there are several key differences between the Winyah and Buck projects that impact cost. Most importantly, the Winyah plant is designed to produce 250,000 tons of ash product per year, while the Buck beneficiation unit *must* produce 300,000 tons of ash product per year to meet CAMA requirements. (Tr. vol. 24, 85; Garrett/Moore Cross Examination Exh. 3 (Fedorka Aff.).) CAMA's output requirement necessitated installation of a second external heat exchanger at Buck along with all associated equipment. Witness Moore did not perform any analysis as to the impact of costs of going from 250,000 tons of ash to 300,000 tons. (DEC Tr. vol. 20, 303.) Importantly, the Duke units must be designed to ensure this output to comply with CAMA a point that witness Moore appears to discount without any analysis to support his view. (Id. at 305.) The Commission is persuaded and affords significant weight to witness Bednarcik's testimony that the onus to ensure the Company's beneficiation unit meets the output requirements of CAMA *at all times* works a significant additional challenge with which the Winyah facility does not have to contend. (DEC vol. 24, 84.)

Aside from the output challenges imposed by CAMA, the record reflects additional structural differences between the two facilities that impact cost. For example, Winyah typically uses 67 percent ponded ash and 33 percent production ash. (Id. at 85.) Ash at the Company's plants, on the other hand, is 100 percent ponded ash and required the addition of a grinding circuit to meet American Society for Testing Materials (ASTM) standards for concrete. (Garrett/Moore Cross Examination Exh. 3 (Fedorka Aff.). The two facilities also use different scrubbers, and the dry scrubbers at Buck required a second bag house with additional induced draft fans. (Tr. vol. 21, 85.) Finally, the Winyah STAR facility was a refurbishment/addition to an existing carbon burn-out facility and SEFA was able to reuse a significant part of the carbon burn-out facility when constructing Winyah's STAR unit. The Company's facilities are new construction. (Tr. vol. 21, 85.) For all of these reasons, the Commission agrees with the Company that the construction cost estimate included in SEFA's RFI is not a reliable marker for evaluating the reasonableness and prudency of the costs to construct the Buck beneficiation unit, and, in any event, witness Moore cannot offer any conclusive evidence that H&M could have completed the project at the cost quoted in SEFA's RFI.

Indeed, through the RFI response SEFA it is clear that the amounts quoted by SEFA are not firm, but only offered a data point of the cost of the Winyah STAR facility. As was pointed out on cross of witness Moore SEFA was clear that pricing "would be finally determined following identification of each location and the development of comprehensive plans and specifications for such Duke Star facilities. (Tr. vol. 20, 314.) Although SEFA moved forward in the process of developing the beneficiation facilities, H&M did not. (Tr. vol. 25, 58-59.) There is no evidence in this record for what pricing H&M would have offered for CAMA designed site specific beneficiation facilities. What is clear from the evidence presented is that DEC had an obligation to comply with CAMA's requirements including the development of three beneficiation facilities, and that the Company utilized a competitive solicitation to identify qualified contractors able and willing to undertake the work required by CAMA.

The Commission likewise is not persuaded by witness Moore's contention that the Company should have solicited additional bids for the work and/or contracted with multiple EPC contractors to build the beneficiation units. After H&M declined the project, in January 2017, the Company sent out an RFP for the balance of plant engineering and construction to four Companies – CBI, Fluor, Kiewit, and Zachry. Each of these companies were engaged in current EPC contracts with the Company and/or had successfully worked with the Company in the past. (Tr. vol. 24, 207.) Witness Moore fails to articulate any reason why it was not reasonable and prudent for the Company to target and solicit bids from these four contractors with proven success, nor does he affirmatively identify any other contractor with whom the Company should have contracted. The Company held a comprehensive RFP and Zachary scored the highest and was selected. As was previously indicated H&M removed itself from contention even after the Company reached out to H&M and held discussion with them in advance of the RFP being issued. (Tr. vol. 25, 58.)

Additionally, witness Moore's alternative suggestion that the Company should have engaged three separate EPC subcontractors is likewise specious. As witness Bednarcik notes, witness Moore did not even consider whether SEFA had the capacity to support three separate contractors. Perhaps most importantly, witness Moore's proposal ignores economies of scale the Company was able to realize by executing a single contract, using a single engineering facility design for all three beneficiation sites. (Tr. vol. 21, 87.) Indeed, as acknowledged by witness Moore, SEFA's own RFI response gave significant weight to the cost saving from the economies of scale achieved by combining the projects, noting the "significant cost savings available from bundling of purchasing for all three facilities and the economies of scale in stating design, construction, and startup activities[.]" (Tr. vol. 20, 326-27.) Moreover, it is pure speculation that H&M would be able to construct a singular plant at a hypothetical cost without H&M actually providing a bid. (Tr. vol. 25, 42.) As noted by witness Bednarcik on cross-examination, the concerns that H&M may have had with "scope" that appear to be the basis of questions from Public Staff are not as easily defined by the number of projects. Instead, H&M's primary concerns were related to the Company's mandatory project controls and oversight which are all standard in Duke's large construction projects whether it be one project or a combination of projects. (Tr. vol. 25, 42-43.) What is clear is that witness Moore was unable to provide any credible support for his argument. In short, witness Moore's proposal amounts to nothing more than unsupported hypotheticals that are insufficient evidence upon which to impose a disallowance.

Witness Moore's remaining arguments in favor of disallowance are equally unconvincing. His suggestion that the Company should have sought statutory relief from CAMA's beneficiation requirements is not a real world solution. First, putting aside the assumption that Mr. Moore is making without support that the amendments to CAMA that included the requirement for beneficiation were not well understood when passed by the legislature, there is no guarantee that the General Assembly would have actually granted such relief The General Assembly was very specific regarding the type of beneficiation projects it intended to have constructed and the timetable for their operation. There is no mention of cost within the statute, nor is there any evidence that suggest that Duke's cost incurred for compliance with the beneficiation requirement is outside the range of what was contemplated by the General Assembly. Indeed, the cost incurred by Duke reflects the cost necessary to meet the very specific requirements of the statute. If the General Assembly had premised the statute upon a level of cost lower than what the Company has incurred to comply the statute would have reflected that, but it does not. Even under Mr. Moore's alternative world analysis, had the General Assembly taken action , it is almost a certainty that the original CAMA deadline would have passed before such a bill could be drafted, vetted, and passed.

Likewise, Witness Moore's suggestion that the Company should have sought guidance from DEQ upon learning of Zachry's estimated EPC costs is also misguided. DEQ is responsible for enforcing the State's environmental laws irrespective of an entity's cost of compliance. There are no cost considerations in the beneficiation provisions of CAMA and it would therefore be inappropriate for DEQ to make such considerations as part of its enforcement.

In sum, the Commission finds the evidence put forth by witness Moore in support of his proposed disallowance to be severely lacking and accordingly it rejects the disallowance.

Conclusion

In summary, DEC has shown by the greater weight of the evidence that its coal ash basin closure costs actually incurred over the period from January 1, 2018, through January 31, 2020 (a) known and measurable, (b) reasonable and prudent, and (c) where capital in nature used and useful, and, as such, those costs are recoverable in rates. Furthermore, for all of the reasons already articulated in this section, full recovery of such cost shall occur through amortization over five years during which the Company shall receive its WACC return on such cost during the amortization period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 75-76

The evidence supporting these findings and conclusions is contained in the Public Staff Partial Stipulations, the Customer Group Stipulations, NCSEA and NCJC et al. Stipulation, Vote Solar Stipulation, DEC's verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

After giving effect to the approved Public Staff Partial Stipulations, the Customer Group Stipulations, the NCSEA and NCJC et al. Stipulation, the Vote Solar Stipulation, and the Commission's decision on the Unresolved Issues, the Commission approves the Company's proposed revenue increase of $414,433,000, as set forth in McManeus Second Settlement Ex. 2, to be further adjusted by the Public Staff's recommended adjustments for the May 2020 Updates, which the Company accepts,[48] reduced by ($310,779,000) through the EDIT Rider,[49] for a net proposed increase in revenue of

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[48] The Company's revenue requirement will be revised to incorporate the impact of the Public Staff's May 2020 Updates adjustments when the Company makes its compliance filing in accordance with this Order. The total impact on the base revenue requirement of the Public Staff's Second Partial Stipulation settled items is listed as ($953,000) on Boswell Second Supplemental and Stipulation Exhibit 1, but this value does not include the impact of Public Staff witness Metz's September 8, 2020 adjustments to remove the capital costs associated with the Lincoln County Combustion Turbine 17 (referred to herein as the Lincoln CT Plant, $14,295,381.65 (system costs), Metz Second Supplemental Testimony at 4) and Project Focal Point ($3,715,121.40 (system costs), Metz Second Supplemental Testimony at 5), which the Company accepts. These amounts are embedded in the Public Staff's adjustments to plant in service, accumulated depreciation, and depreciation rates in the Unsettled Issues listed in Boswell Second Supplemental and Stipulation Exhibit 1.

[49] The EDIT flowback estimate of ($310,779,000) is based on an estimate of the amount to be flowed back to customers through the Company's interim rates and is subject to change based on the actual amount flowed back when the revised rates approved in this Order go into effect.

$103,654,000. The approved revenue increase is based on the following amounts of test year pro forma operating revenues, operating revenue deductions, and original cost rate base (under present rates), which are to be used as the basis for setting rates in this proceeding: $5,209,138,000 of operating revenues, $4,000,325,000 of operating revenue deductions, and $17,166,748,000 of original cost rate base.

Pursuant to N.C.G.S. § 62-133(a), the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors, (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe, and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. *See* N.C.G.S. § 62-133(b). DEC's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to the Company's individual customers, as well as to the communities and businesses served by the Company. DEC presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

Based on all of the evidence, the Commission finds and concludes that the revenue requirement, rate design, and the rates that will result from this Order strike the appropriate balance between the interests of DEC's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DEC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the revenue requirement and the rates that will result from that revenue requirement established as a result of this Order are just and reasonable under the requirements of N.C.G.S. § 62-30, *et seq*.

IT IS, THEREFORE, ORDERED as follows:

26. That the Harris Teeter Stipulation filed by DEC is approved in its entirety;

27. That the Commercial Group Stipulation filed by DEC is approved in its entirety;

28. That the OPT-VSS rate schedule shall be modified in accordance with the Harris Teeter Stipulation and Commercial Group Stipulation;

29. That the CIGFUR Stipulation filed by DEC is approved in its entirety;

30. That unprotected EDIT and deferred revenue should be refunded to customers on a uniform cents per kWh basis as provided in the CIGFUR Stipulation and reflected in Pirro Second Settlement Ex. 9;

31. That the NCSEA and NCJC et al. Stipulation filed by DEC is approved in its entirety;

32. That the Vote Solar Stipulation filed by DEC is approved in its entirety;

33. That the Company's request to amortize the loss on the sale of the Hydro stations over a seven-year period is approved;

34. That DEC shall recalculate and file the annual revenue requirement with the Commission within 10 days of the issuance of this Order, consistent with the findings and conclusions of this Order and the Public Staff Partial Stipulations. The Company shall work with the Public Staff to verify the accuracy of the filing. DEC shall file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determination in this proceeding;

35. That DEC is hereby authorized to adjust its rates and charges in accordance with the Public Staff Partial Stipulations and findings in this Order effective for service rendered on and after the following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 36;

36. That the Commission shall issue an Order approving the final revenue requirement numbers once received from DEC and verified by the Public Staff as soon as practicable;

37. That the depreciation rates proposed by DEC in this case are approved;

38. That DEC shall recover the deferred actual coal ash basin closure costs it has incurred during the period from January 1, 2018 through January 31, 2020, along with financing costs through July 2020, for a combined total amount of $378 million. These costs shall be amortized over a five-year period, with a return on the unamortized balance at DEC's weighted average cost of capital authorized in this case;

39. DEC's request to continue the deferral for environmental CCR compliance costs incurred after the cut-off date for this rate case of January 31, 2020, including the depreciation and return on CCR compliance investments related to continued plant operations placed in service on or after January 31, 2020, and a return on both deferred balances at the overall rate of return approved in this case, shall be, and is hereby approved;

40. That within 30 days of this Order, but no later than ten business days prior to the effective date of the new rates, DEC shall file for Commission approval five copies of all rate schedules designed to comply with this Order, accompanied by calculations showing the revenues that will be produced by the rates for each schedule; and

41. That DEC shall submit a proposed customer notice to the Commission for review and approval, and upon approval of the notice by the Commission, shall give appropriate notice of the approved rate increase by mailing the notice to each of its North

Carolina retail customers during the billing cycle following the effective date of the new rates.

ISSUED BY ORDER OF THE COMMISSION.

This the ______ day of______________, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell, Chief Clerk

CERTIFICATE OF SERVICE

DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1187

I hereby certify that a copy of the foregoing **DUKE ENERGY CAROLINAS, LLC FINDINGS AND CONCLUSIONS FOR PROPOSED ORDER REGARDING ISSUES UNRESOLVED BY THE PUBLIC STAFF PARTIAL STIPULATIONS** was served electronically or by depositing a copy in United States Mail, first class postage prepaid, properly addressed to the parties of record.

This the 4th day of November 2020.

/s/ Camal O. Robinson
Camal O. Robinson
Assistant General Counsel
Duke Energy Corporation
550 South Tryon Street
Charlotte, North Carolina 28202
Telephone: 980.373.2631
Camal.robinson@duke-energy.com